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Witness: A. Havenar-Daughton

MARIN CLEAN ENERGY

PREPARED DIRECT TESTIMONY OF ALICE HAVENAR-DAUGHTON

IN RULEMAKING 20-11-003

September 1, 2021

MARIN CLEAN ENERGY

PREPARED DIRECT TESTIMONY

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INTRODUCTION AND SUMMARY OF TESTIMONY

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I. INTRODUCTION AND SUMMARY OF TESTIMONY

In accordance with the Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2 of Rulemaking 20-11-003, issued on August 10, 2021 ("Amended Scoping Memo"), the August 11, 2021 E-mail Ruling of Administrative Law Judge Stevens outlining guidance for party proposals ("Proposal Guidelines"), and the August 16, 2021 E-Mail Ruling enclosing the Energy Division Staff Concept Paper ("Staff Concept Paper"), Marin Clean Energy ("MCE") presents this Opening Testimony in Rulemaking ("R.") 20-11-003 (the "Rulemaking").

Altogether, these materials direct parties to develop or comment upon proposals designed to achieve peak load reduction and improved grid reliability by the end of summer 2021, and at least through 2022 and 2023, consistent with Governor Newsom's July 30, 2021 Emergency Proclamation ("Emergency Proclamation").[1] The Emergency Proclamation directs all state agencies "to act immediately" to find ways to make up for the "projected energy supply shortage of up to 3,500 megawatts during the afternoon-evening 'net-peak' period of high power demand on days where there are extreme weather conditions."[2]

As detailed below, MCE has developed—and launched—three distinct customer programs that the Commission can leverage to quickly achieve net peak demand reductions and improved grid reliability if the Commission authorizes ratepayer funding to expand and support these programs. In addition to these program proposals, MCE submits comments on the Staff Concept Paper to encourage the Commission to ensure that any program designs or rule modifications that it adopts in this Rulemaking are consistent with the goals of the Emergency

[1] Proclamation of a State of Emergency, July 30, 2021, *accessible at*: https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.
[2] *Id*.

Proclamation and will support—or at least not conflict with—a market-driven approach to achieving peak load reduction and improving grid reliability.

A. MCE's Relevant Background

MCE, California's first Community Choice Aggregator ("CCA"), is a not-for-profit public agency that began service in 2010 with the goals of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs. MCE is a load-serving entity ("LSE") serving approximately 1,200 MW peak load, providing electricity generation services to more than 1.1 million people in 36 member communities across Contra Costa, Marin, Napa, and Solano counties.

MCE has extensive experience running customer programs that span the entire breadth of distributed energy resources ("DERs") from Energy Efficiency ("EE") and Energy Storage to Demand Response ("DR) and Transportation Electrification ("TE"). In 2013, MCE became the first CCA to serve as a program administrator of ratepayer-funded EE programs.[3] Since 2017, MCE has been expanding its DER program portfolio, which now includes initiatives focused on low-income solar, community solar programs for disadvantaged communities ("DACs"), energy storage, DR and TE.

MCE's Director of Customer Programs, Alice Havenar-Daughton, prepared this Opening Testimony on behalf of MCE. In accordance with Commission Rule 13.8, Ms. Havenar-Daughton's statement of qualifications is attached hereto as Appendix A.

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[3] MCE currently administers programs in multifamily, single family, commercial, agriculture, and industrial sectors. Furthermore, MCE administers the Low-Income Families and Tenants (LIFT) program under the umbrella of the state's Energy Saving Assistance ("ESA") program.

B. Purpose and Brief Summary of Opening Testimony

As stated above, MCE submits this Opening Testimony for the Commission's consideration of ways to achieve peak load reduction and improve grid reliability, consistent with the Emergency Proclamation and the goals of this Rulemaking.

In Chapter 2, MCE submits a funding request to leverage and expand three of MCE's demand flexibility programs that are extremely well-positioned to address the grid's reliability needs. First, the *Peak FLEXmarket* program is a new demand flexibility program that MCE launched on June 1, 2021, which is uniquely capable of achieving peak load reduction at scale. The *Peak FLEXmarket* can generate impacts from new demand flexibility providers and projects, all while minimizing risk to ratepayer funding and improving upon the measurement and verification of demand flexibility resources. Additionally, MCE developed an *Energy Storage Program* and an Electric Vehicle ("EV") charging program—*MCEv Sync*—that are each designed to align customer charging and discharging behaviors of the respective DERs with grid needs and to reduce demand during times of grid stress.

MCE requests that the Commission authorize ratepayer funding to expand and scale these programs, which are already in development and present a low-hanging fruit opportunity to achieve demand reductions in time for summers 2022 and 2023.

Specifically, MCE requests funding authorization as follows:

- $11,560,000 to expand upon the success of its *Peak FLEXmarket* program;
- $4,408,000 to leverage MCE's *Energy Storage Program*; and
- $1,776,000 to leverage MCE's EV charging program, *MCEv Sync*.

Notably, MCE recommends that the vast majority of this funding request—*i.e.*, the entire budget proposal for expansion of the *Peak FLEXmarket* program—be drawn from MCE's remaining budget in unrequested EE funds,[4] which currently approximates $11.9 million.[5] For clarity and transparency, MCE notes that it included this same funding request for *Peak FLEXmarket* expansion in Opening Comments filed by MCE on August 31, 2021 in Rulemaking 13-11- 005. These requests are not to obtain duplicative funds, but instead to allow the Commission flexibility in determining under which proceeding the funding authorization would be more appropriate, and given that the Peak FLEXmarket is responsive to the needs identified in both R.13-11-005 and R.20-11-003.

In Chapter 3, MCE submits comments on the Staff Concept Paper. These comments urge the Commission to ensure that any demand response ("DR") program proposal and/or program modification adopted in this Rulemaking maintain a level playing field among CCAs, investor-owned utilities ("IOUs"), and third-party DR-Providers ("DRPs"). MCE is concerned that certain of the program proposals raised in this proceeding and discussed in the Staff Concept Paper may limit MCE's demand flexibility programs' expansion opportunities, and will have long-term, anti-competitive impacts on non-IOU DR programs. Any such "monopolization" of DR programs with the IOUs would limit innovation in creating new demand flexibility opportunities for customers. MCE strongly encourages the Commission to reject any such program proposals or modifications that would derail the significant CCA momentum in developing innovative demand flexibility programs by routing ratepayer funding strictly to IOU-administered DR programs.

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[4] MCE defines "unrequested funds" as the differences between the funds approved in MCE's Business Plan (*see* A.17-01-017, filed January 17, 2017 and as trued up in MCE's 2019 annual budget advice letters ("ABAL"), and the total budget that MCE has requested to date in its ABAL, which amount currently approximates $11.9 million.

[5] It is important to note that MCE, unlike the investor-owned utilities, was not directed to use the "unrequested funds" for the implementation of the AB 841 School EE Stimulus Program. (*See* D.21-01-004, *Decision Providing Directions for Implementation of School Energy Efficiency Stimulus Program*, at 8, issued in R.13-11-005.) Hence, these funds remain available for use by MCE.

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CHAPTER TWO

PROGRAM PROPOSALS

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I. INTRODUCTION

MCE proposes that the Commission leverage three of MCE's existing programs to capture and quickly deploy innovative peak load reduction measures in furtherance of the goals espoused in the Emergency Proclamation. Specifically, MCE submits for the Commission's consideration MCE's (1) *Peak FLEXmarket*; (2) *Energy Storage Program*; and (3) *MCEv Sync*, a managed EV charging program. For consistency and ease of review, the proposals described below adhere to the outline numbering included in the Proposal Guidelines.

II. MCE PROGRAM PROPOSALS

1. *Peak FLEXMarket* Program

On June 1, 2021, MCE launched a self-funded demand flexibility program, the *Peak FLEXmarket*, which is the logical extension of MCE's Commercial Energy Efficiency Market program and is well-positioned to deliver net peak demand reduction on a broad scale.

As background, MCE's Commercial Energy Efficiency Market program is a first-of-its-kind EE program that pays participating vendors based on the metered savings' net benefits, which are heavily weighted towards peak period hours and therefore incent load-shaped EE. It is a population-level normalized metered energy consumption ("NMEC") program[6] that leverages the CalTRACK methods and is further supported by comparison group analyses.[7] This thorough measurement protocol ensures a high degree of confidence in measured savings.

MCE worked with Recurve,[8] an industry leader in meter-based measurement, to launch the Commercial Energy Efficiency Market in early 2021 with a ~$1M budget. The program quickly

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[6] *See* NMEC Rulebook, Version 2.0 at 5, 10-13 (January 7, 2020) ("NMEC Rulebook").
[7] *See* CalTRACK Hourly Methods, *available at* https://www.recurve.com/how-it-works/caltrack-hourly-methods
[8] Recurve tracks changes in consumption due to program interventions for both individual buildings and in aggregate to support resource planning and facilitate performance-based transactions. (*See* https://www.recurve.com/)

expanded to a ~$5M annual budget, largely due to the ease of participation and strong interest from aggregators.[9]

Since the Commercial Energy Efficiency Market compensates aggregators based on the avoided cost value[10] of their projects, weighted heavily towards peak hours, much of the early program interest came from aggregators that are active in the DR arena. However, to date, MCE has not been able to pay for the demand flexibility they could deliver with Commission-approved EE funds. This is because demand flexibility impacts (*i.e.*, peak period savings) and resources (*e.g.*, energy storage systems ("ESS"), behavioral DR, *etc.*) do not fit within the current EE framing, which measures project value based on equipment useful life, measure load shapes, customer cost considerations, and other elements that are outside of the valuation of demand flexibility as a resource.

To ensure that the value of these demand flexibility resources was not overlooked, MCE launched the *Peak FLEXmarket* program off of the same platform.[11] The *Peak FLEXmarket* operates in parallel to, and even complements, MCE's Commercial Energy Efficiency Market. Whereas the Commercial Energy Efficiency Market is restricted to cost-effective EE in the commercial sector, the *Peak FLEXmarket* is open to all customer segments and is focused specifically on load shifting, shaping and demand reduction during the peak summer hours.

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[9] Aggregators are participating vendors or program partners who generate energy efficiency savings for an aggregated group of customers. Aggregators must execute a Flexibility Purchase Agreement with Recurve to participate in the program.

[10] Energy + Environmental Economics ("E3") developed the methodology for estimating the value of avoided costs for use in evaluating distributed energy resource programs in California. *See* https://www.ethree.com/public_proceedings/energy-efficiency-calculator/ ("E3 Avoided Cost Calculator").

[11] MCE's Commercial Energy Efficiency Market and *Peak FLEXmarket* run off of Recurve's "Demand FLEXmarket" platform.

MCE moved quickly in the spring of 2021—using its own ratepayer funds—to launch the *Peak FLEXmarket* and close the value gap for flexibility resources. While MCE proactively self-funded the initial *Peak FLEXmarket* in 2021, on an emergency basis and in the public interest, funding for 2022 and 2023 has yet to be identified. If the *Peak FLEXmarket* is to scale to the expansive level it is designed for, MCE will require access to additional funding. Accordingly, MCE respectfully submits the following proposal, in accordance with the Proposal Guidelines.

a. General Program Design

MCE's *Peak FLEXmarket* is a market-driven demand flexibility program that assigns an hourly value to measured, behind-the-meter ("BTM") impacts. The *Peak FLEXmarket* is supported by a robust measurement and verification ("M&V") platform, which is regularly updated with smart meter data covering MCE's entire service area. The *Peak FLEXmarket* tracks enrolled projects to assess their peak period impacts and value. The platform can also target customers for engagement, based on a variety of classifications and load characteristics such as annual usage, peak usage, cooling-dependent load, their "ramp" and more. Whereas MCE's Commercial Energy Efficiency Market assigns hourly value based on the Avoided Costs, the *Peak FLEXmarket* integrates an hourly value for peak hours as determined by MCE (or the Commission, should this request for funding be approved).[12]

Even more promising, the *Peak FLEXmarket* has successfully engaged new aggregators who have never participated in DR, as well as program partners who have traditionally supported EE programs. *Peak FLEXmarket* presents these partners with an innovative value proposition for demand flexibility, which can be incorporated into new project specifications and incentive structures now, and in the build-up to June 1, 2022.

[12] *See* E3 Avoided Cost Calculator.

As further described in Section 1.a.iv, the *Peak FLEXmarket* offers compensation for both daily load shifting and event-driven DR, or DR alone. One of the primary attributes of a price-signal driven program is that it enables the *Peak FLEXmarket* to remain technology agnostic- it is simply a program framework with the tools to measure and value hourly reductions in energy use. This has a number of strategic benefits:

- MCE avoids prescriptive solutions for how load reduction should occur;
- There is minimal risk to program funding, as program payments are made entirely on a performance basis;
- MCE scaled the program quickly and can continue to expand, by avoiding the administratively burdensome process of launching direct contracts with aggregators; and
- The program design is simple and attractive to demand flexibility providers, including those more traditionally aligned with EE programs, and lends itself to more integrated program offerings (*e.g.*, DR and EE).

Customers and/or aggregators can participate under the *Peak FLEXmarket* with a behavioral DR offering, a device-enabled strategy (*e.g.*, batteries, smart thermostats), or any other solution that generates verifiable results at the meter. By offering a payment for energy reductions that values a range of resources equally, the *Peak FLEXmarket* ensures that incentives flow to projects with verifiable impacts and allows for different BTM solutions to work together in a coordinated way.

i. Program Trigger

The *Peak FLEXmarket* works to incent load reductions during summer peak periods in two ways: (1) daily load shifting (referred to as "Flex Savings" in the *Peak FLEXmarket*) and (2) demand response (referred to as "Resiliency Events" in the *Peak FLEXmarket*).

Flex Savings are not "triggered"; rather, they are measured and payable across all weekday peak hours (4pm - 9pm) throughout the peak season (June 1 through October 31). While the incremental value of Flex Savings may be small —both as a policy objective and based on their payment rate—incorporating this value is central to stronger engagement in DR programs because:

- It ensures that load shifting out of the peak hours becomes common practice, consistent and achievable, rather than leaning on DR purely as an emergency lever;
- It allows for numerous DR solutions to be leveraged every day and not just during DR events. Traditional DR baseline measure methods and incentive structures may result in a disincentive to regularly reduce demand and therefore fall short of their potential. This dilemma is resolved through the *Peak FLEXmarket's* innovative M&V methods, as further described in Section 1a.vi.;
- There are carbon, grid resiliency, and cost benefits that can be realized if load-shifting is more commonly practiced; and
- Daily load shifting aligns with customer benefits. Indeed, customer potential for cost avoidance on a daily basis may even outweigh the benefits of standalone DR.

Resiliency Events are currently called at the discretion of MCE though they have largely aligned with CAISO Flex Alerts. They are intended to incentivize demand reduction during periods of high grid congestion, power shortages, or high prices. Resiliency Events to-date have been triggered when CAISO day-ahead ("DA") Market prices exceed $200/MWh for more than 2 hours, or when one hour exceeds $300/MWh. In future summers, the *Peak FLEXmarket*'s triggers could easily be adjusted to the CAISO's Alert, Warning, Emergency ("AWE") process.[13]

[13] CAISO AWE emergency notifications are issued "when operating reserves or transmission capacity limitations threaten the ability of the California ISO to safely and reliably operate the grid." (*See* CAISO http://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx).

Participants are notified no less than 24 hours in advance of a Resiliency Event.

ii. Demonstration that program will deliver benefits during net peak

The *Peak FLEXmarket* only pays for net impacts delivered during peak hours; there are no upfront program payments to aggregators or fixed incentives. Therefore, the vast majority of program payments are directly tied to net peak energy impacts.

Further, the *Peak FLEXmarket* is well-positioned to scale quickly to deliver expanded benefits during net peak by increasing enrollment opportunities. Within the first three months of program operations, the *Peak FLEXmarket* had already enrolled seven aggregators, and is actively engaging with ten more. Four aggregators have submitted their first enrollments, with 1,465 meters assessed for eligibility, and 304 meters being actively tracked within aggregator portfolios.

iii. Program performance requirements

The *Peak FLEXmarket* incorporates the following performance requirements to ensure that load reductions are achieved:

(1) <u>"Full Participation" Performance Payments</u>

Measurement and payment for "Full participants", *i.e.*, those participating in both Resiliency Events and Flex Savings, are made on a monthly basis and are calculated by taking the sum of Flex Savings and Resiliency Event savings, and multiplied by the applicable Payment Rate (as outlined in section 1.a.iv. below). For the summer of 2021, there are no consequences for underperformance within the *Peak FLEXmarket*, but negative savings[14] detract from the payment at 1.2x the rate that measured savings generate payments. For optimal results, aggregators will want to make sure to shed load across the entire 4 - 9 pm period. Monthly payments will therefore have a minimum payment of $0 at a portfolio level; individual hours of negative savings will be

[14] Negative savings are increases in energy use over the baseline during peak hours.

included in the total monthly calculation to arrive at "net" impacts. The increased incentive levels associated with Resiliency Events will be incorporated into the calculation of the net value generated by Full Participants.

(2) Resiliency Event Payments

Resiliency Event payments are calculated as the savings generated during each Resiliency Event within the peak hours. However, individual hours of negative savings will be included in the calculation of the net total of the event. The asymmetric cost function mentioned above is only applicable to non-event days. During resiliency events, negative savings offset positive savings at one for one ratio.

iv. Compensation structure

MCE developed the below payment structure to quickly launch the *Peak FLEXmarket* program and gauge its potential. However, to rapidly expand the program—consistent with the Emergency Proclamation's directive to "act immediately" to "expand[] and expedite[]" DR programs that will "reduce strain the energy infrastructure", MCE requests additional funding to increase incentive levels for Resiliency Events for summers 2022 and 2023. Increasing these incentive levels will also allow MCE to remain competitive with other DR programmatic offerings.

In its current form, which is subject to iteration and improvement as the program scales, Flex Savings are paid at $150/MWh for all energy reductions during summer peak periods (a rate that is currently aligned to approximate average summer peak avoided cost values). For Resiliency Event participation, aggregators are currently paid at the day-ahead ("DA") Market price, ranging from $200-$800/MWh. Payments for both pathways in the *Peak FLEXmarket* are made on a monthly cadence after all program data is collected and analysis completed.

The compensation structure for Resiliency Events can and should be adjusted in future years to align with the statewide valuation of DR. Resiliency Event savings would be most effective if aligned with the incentive payment levels set in the Emergency Proclamation and other DR or demand flexibility programs offered by other Program Administrators.[15] It is important for the value of grid resiliency and demand reduction, as a resource, to remain consistent between the different programmatic offerings (as much as practicable, and with possible exceptions for LSE-controlled loads, DR programs with equity goals, *etc.*). Without a consistent value for peak demand reduction, it is likely that aggregators, implementers, and other providers will simply invest their energy in the most lucrative program and/or markets, picking winners and losers in the process. Rather than driving the market towards programs with payment levels that are inflated depending on available funding resources, the market should be driven towards programs that are best aligned to achieve grid resiliency and other policy goals.

v. Program Eligibility and Enrollment

Program Eligibility

The *Peak FLEXmarket* is currently offered only to unbundled customers in MCE's service territory, but if ratepayer funding were approved as requested herein, program enrollment would be expanded to include bundled customers as well.

The *Peak FLEXmarket* is agnostic to customer market segment and building type but it is best applied to customer segments with consistent load shapes, for whom a comparison group can readily be drawn per the program's current M&V Plan.[16] Customers with highly unique load

[15] For example, load reductions are currently valued at $1,000/MWh under the IOU's Emergency Load Reduction Program ("ELRP"), a rate that is likely to be increased to $2,000/MWh under the Governor's Emergency Proclamation.

[16] For commercial customers, the primary strategy to assemble the comparison group will be to weight the number of meters by business type (determined by NAICS codes) such that the comparison group has the same proportionality as the treatment group. Residential comparison groups will be created using distance-based matching or stratified sampling. Read more at *Peak FLEXmarket* Implementation and M&V Plan, *accessible at* https://www.demandflexmarket.com/mv-plan.htm.

shapes (*e.g.,* large industrial customers) are not an optimal fit for the *Peak FLEXmarket* at present, or may only qualify for Resiliency Event payments.

The *Peak FLEXmarket* is also technology and measure agnostic, which is intentional and one of the program's key attributes. Indeed, since it is technology agnostic, *Peak FLEXmarket* is capable of integrating a wide range of demand management strategies and clean DERs, including ESS, smart thermostats, building/equipment controls and behavioral DR. By offering a payment for energy impacts that value technologies and strategies equally, the *Peak FLEXmarket* ensures that program incentives are directed towards the technologies and providers that can deliver energy impacts most effectively. And since aggregators have flexibility in delivering projects, this minimizes performance risk to the program while optimizing the deployment of demand flexibility solutions.

<u>*Program Enrollment*</u>

At this point in time, customers must enroll under the *Peak FLEXmarket* program through participating aggregators. Aggregators enroll by signing a "Flexibility Purchase Agreement," which outlines the key MCE requirements and terms of participation. Aggregators may then submit customers to the *Peak FLEXmarket*, where they are pre-screened for data sufficiency, potential dual DR program enrollment, and other factors that may impact eligibility. Once eligibility is confirmed, an aggregator's customer portfolio is tracked, and aggregators are compensated for net load[17] shifting out of the peak hours during summer months in 2021.[18]

MCE is also exploring pathways to offer direct customer enrollment in the *Peak FLEXmarket* under an MCE-aggregated portfolio for larger, non-residential customers (>200 kW). Customers would be presented with the opportunity to receive direct program payments from the

[17] The net load is calculated to account for any days with a load increase.
[18] The defined summer period in 2021 runs from June through October.

Peak FLEXmarket (*i.e.*, without an aggregator determining customer rates). While the *Peak FLEXmarket* leans heavily on aggregator-driven participation, MCE business relationship managers also encounter large customer accounts that are interested in demand response, but not currently enrolled in a program. Furthermore, MCE is capable of targeting the customers who may benefit from this the most, based on their peak demand, load shape attributes and sensitivity to weather. Direct participation - for customers who are well-equipped to manage their own load - would allow customers to receive the program's full incentive value, which may generate stronger peak period savings.

vi. Measurement and Verification ("M&V")

As described in Section 1.a.iii above, the Peak *FLEXmarket* offers two participation pathways: (1) the "Full Participation" model under which customers reduce load both on a daily basis and during Resiliency Events, and (2) Resiliency Event participation only for customers who do not participate in daily load shifting. Measurements for both participation pathways are derived by Recurve, according to the process that is thoroughly detailed in the program's M&V Plan.[19]

Energy impacts are determined through the open source CalTRACK 2.0 methods.[20] In brief, the CalTRACK methods quantify the weather-normalized, occupancy-dependent change in energy use for each hour as compared to past usage.[21] Recurve also applies the open-source GRIDmeter methods[22] for a comparison group adjustment for each portfolio. To ensure that the impacts measured by the program reflect the impacts of the program intervention, the *Peak*

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[19] *See Peak FLEXmarket Implementation and M&V Plan*, May 2021, *available at* https://www.demandflexmarket.com/mv-plan.html.

[20] The current v. 2.0 CalTRACK methods documentation and technical appendix are *available at* http://docs.caltrack.org/en/latest/methods.html .

[21] Background on the development of CalTRACK and the OpenEEmeter is *available at* www.caltrack.org.

[22] A description of the Recurve GRIDmeter method is *available at* https://grid.recurve.com/.

FLEXmarket's M&V Plan outlines a process for handling non-routine events, specific project eligibility considerations, and thresholds for statistical confidence.[23]

Overall, the *Peak FLEXmarket*'s M&V methods demonstrate a substantial improvement over commonly used DR baseline methodologies such as the "10 in 10", which may in fact undervalue DR impacts, inhibit load shifting and thus discourage deeper engagement from providers and customers.[24]

This new methodology unlocks tremendous untapped potential. Not only has it been shown to produce substantially better results than other DR measurement methods,[25] it also presents an opportunity for the program to value and reward regular load-shaping, which may be the key to unlocking the customer value proposition of flexible technologies.

b. Program Administration

MCE's *Peak FLEXmarket* is administered by MCE. Recurve provides support in M&V and program implementation services.

c. Program Marketing, Outreach and Education

Customer enrollment in the *Peak FLEXmarket* program currently occurs through aggregators. Hence, MCE's marketing, education and outreach ("ME&O") efforts to date have mostly focused on educating and recruiting aggregators for participation in the program. Within

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[23] *See Peak FLEXmarket* Implementation and M&V Plan, *accessible at* https://www.demandflexmarket.com/mv-plan.htm.

[24] *See* Marc Pare, Mariano Teehan, Stephen Suffian, Joe Glass, Adam Scheer, McGee Young & Matt Golden, "Applying Energy Differential Privacy to Enable Measurement of the OhmConnect Virtual Power Plant: A study of Demand Response during the California August 2020 blackouts" (December 2020), *available at* https://assets.website-files.com/5cb0a177570549b5f11b9550/6050a2a48c39eb09319c9382_Quantifying%20The%20OhmConnect%20Virtual%20Power%20Plant%20During%20the%20California%20Blackouts%20(1).pdf.

[25] *Id.*

its first three months of operation, the *Peak FLEXmarket* generated new participation, including aggregators who have never participated in DR programs before. These aggregators can now incorporate the value of demand flexibility into their customer engagement, thereby deepening grid resiliency benefits with truly additional projects. In the build-up to summer 2022, MCE intends to continue engaging new aggregators – including vendors and installers that are new to DR and flexibility programs – while also encouraging existing program partners to build the value proposition of the *Peak FLEXmarket* into their program designs and project specifications.

As described in section 1.a.v., MCE also intends to create a pathway for direct customer enrollment in the *Peak FLEXmarket. If MCE determines to pursue this enrollment mechanism, MCE will engage in additional ME&O strategies directly targeting potential program participants.*

d. Program budget

MCE relied on its own ratepayer generation revenues to self-fund and quickly launch the *Peak FLEXmarket* in the spring of 2021. However, to grow the market and expand upon the program's initial success, the Commission should authorize MCE access to ratepayer funds. MCE expects that the *Peak FLEXmarket* can be scaled to accommodate 15 MW of load reduction in the summer of 2022 and 30 MW of load reduction by summer of 2023 if sufficient funding is put in place. MCE proposes that the Commission approve $11,560,000 in program funding to effectuate this growth. MCE offers these load reduction projections as a basis for establishing program funding levels, which need to be meaningful and competitive if they are to stimulate the development of a new market for customer-sided flexibility solutions.

It is also important to emphasize that the vast majority of the Proposed Program Budget in the table below would be paid only on a performance basis, using some of the most advanced

M&V standards available. If savings are not achieved, payments will not be made, translating into a uniquely low-risk opportunity to deploy ratepayer funding.

Table 1: Proposed Program Budget for *Peak FLEXmarket* Expansion in 2022-2023

#	BUDGET ITEM	2022	2023	TOTAL
1.	**Program Administration**	**$270,000**	**$539,000**	**$809,000**
1.1.	Startup Costs	$0	$0	$0
1.2.	Ongoing admin costs	$270,000	$539,000	$809,000
2.	**Incentives**	**$3.083,000**	**$6,165,000**	**9,248,000**
2.1.	Load Shifting Incentives	$1,283,000	$2,565,000	$3,848,000
2.2.	Resiliency Event Incentives	$1,800,000	$3,600,000	$5,400,000
3.	**ME&O**	**$39,000**	**$77,000**	**$116,000**
4.	**M&V**	**$462,000**	**$925,000**	**$1,387,000**
	Total Program Budget	**$3,854,000**	**$7,706,000**	**$11,560,000**

Program Administration Budget

A key advantage to leveraging the *Peak FLEXmarket* to achieve additional load reductions in 2022 and 2023 is that all of the one-time program start-up costs have already been funded through MCE's generation revenues. MCE forecasts modest ongoing administrative costs (at approximately 7% of total program costs) due to the market-driven program participation model, while leveraging "embedded" M&V which limits unsubstantiated or unnecessary spend of ratepayer dollars.

Customer Incentives Budget

As shown in Table 1, MCE's budget projection is largely driven by the incentive payments for Flex Savings and Resiliency Events and the need to maintain a compensation rate that is competitive with other program offerings, particularly those that benefit from ratepayer funding.

MCE calculates the budget for "Load Shifting Incentives" assuming a flex savings rate of $150/MWh for 11.25 MW of daily load shifted between June 1 and October 31, 2022 and 22.5 MW of daily load shifted on weekdays between June 1 and October 31, 2023. This amounts to 75% of the program's load reduction target, at 760 peak period hours. These load shifting assumptions are grounded in the fact that a) not all *Peak FLEXmarket* participants will generate Flex Savings and b) not all will be eligible to do so. However, for the purposes of budget-setting, it is important to ensure that the value of Flex Savings is communicated and that sufficient funding is available to stimulate interest. MCE considers $150/MWh an appropriate rate to offer for measured daily load shifting, since that amount roughly aligns with the average avoided cost value of savings generated during the summer months' peak hours.[26]

MCE calculates the budget for "Resiliency Event Incentives", assuming an incentive rate of $2,000/ MWh for up to 60 hours annually for 15 MW of capacity by June 1, 2022 and 30 MW of capacity by June 1, 2023. MCE notes that an incentive rate for Resiliency Events of $2,000/MWh is currently used for illustrative purposes only. MCE recommends that the final incentive rate for Resiliency Events paid under the *Peak FLEXmarket* program be aligned with the incentive rates provided under other DR programs authorized in the ongoing discussions under

[26] *See* E3 Avoided Cost Calculator.

Rulemaking R.20-11-003 (see more information on the proposed compensation rate in section 1.a.iv. above).

e. Implementation timeline

The *Peak FLEXmarket* has already launched with MCE's support and is currently operating through October 2021. The results of the *Peak FLEXmarket*'s first operating year will be summarized in a report, following complete measurement of the program's impacts and an assessment of the program design. The *Peak FLEXmarket* will be available and prepared to deliver additional demand reduction at net peak in June 2022, provided that additional funding be made available to the program per the request for funding put forward in this Opening Testimony.

If ratepayer funding is provided to the *Peak FLEXmarket*, MCE intends to release an updated Program Manual and M&V Plan and may incorporate revisions to the program design pending feedback from the Commission and stakeholders. In advance of June 2022, MCE intends to (1) evaluate the program's first season of operation (June-October 2021); (2) make updates to the program design, as-relevant; (3) continue to engage aggregators to facilitate deeper engagement; (4) consider developing a participation pathway for direct customer enrollment under a MCE-aggregated portfolio; and (4) integrate the *Peak FLEXmarket* value proposition across MCE's programmatic offerings.

f. Program duration

Under MCE's budget proposal made herein, the *Peak FLEXmarket* program is slated to conclude December 31, 2023, following an evaluation of impacts in the summer season of 2023.

g. Estimated megawatt contribution/load impact

Target load impacts for the summers of 2022 and 2023 are 15 MW and 30 MW, respectively. Energy impact projections are variable, depending on the timeframe of the program, the definition of peak hours, and the proportion of aggregators whose customers generate both

Flex Savings and Resiliency Event impacts, versus those that participate solely in Resiliency Events.

MCE expects that the *Peak FLEXmarket* will not directly reduce the impact of any existing programs. To date, the majority of aggregators participating in the *Peak FLEXmarket* have yet to participate in a DR program - these are truly new and additional resources.

h. Potential interaction with other existing programs (i.e., dual participation issues)

The *Peak FLEXmarket* is geared nearly exclusively towards new project development and recruiting new customers into the program. As noted previously, one of the program's most promising attributes is that it is drawing interest from aggregators and customers who have never participated in DR programs or worked to incorporate the value of demand flexibility into their projects before.

As a general rule, dual participation of DR resources in more than one DR program is not allowed and *Peak FLEXmarket* participants must disclose participation under any other DR program when enrolling under the program.

i. Prior similar program experience in California or elsewhere

Not applicable.

j. Program funding and cost recovery mechanisms

MCE requests the Commission authorize $11,560,000 of ratepayer funds for MCE to scale its *Peak FLEXmarket* to achieve additional net peak demand reduction during the summers of 2022 and 2023. As previously stated, this funding is essential to ensure the program's growth and continued success in delivering peak load reduction. Specifically, this funding authorization is necessary to support an incentive payment rate that will continue to attract participation, and to remain competitive with other program offerings, particularly those that benefit from ratepayer funding.

MCE proposes that *Peak FLEXmarket* funding derive from any unrequested EE ratepayer funds that have accumulated under MCE's current EE funding authorization.[27] MCE defines "unrequested funds" as the differences between the funds approved in MCE's EE Business Plan[28] and the total budget that MCE has requested to date in its EE ABALs.[29] At present, MCE has approximately $11.9 million available in unrequested funds, which would suffice to cover the full budget requested above for the *Peak FLEXmarket* program.

k. Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk

There is minimal risk to ratepayer funding in the *Peak FLEXmarket* since the program infrastructure is already launched and underway, has shown significant enrollment interest, and, crucially, program payments are made on a performance-basis. Still, MCE recognizes some potential risk if there is insufficient participation. However, the *Peak FLEXmarket* was designed to mitigate this risk as much as possible by:

- Limiting barriers to participation, with minimal enrollment requirements for aggregators;
- Pay-for-performance aggregator incentive structures that only rewards load reduction solutions that deliver;

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[27] MCE is a program administrator ("PA") of ratepayer-funded EE programs under the current rolling portfolio cycle. MCE has been administering EE programs under California Public Utilities Code Section 381.1(a)-(d) since 2013. (*See* D.12-11-015, issued Nov. 15, 2012.)

[28] *See* Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan in A.17-01-017, filed January 17, 2017, and as trued-up in the 2019 ABAL filing.

[29] It is important to note that MCE, unlike the investor-owned utilities, was not directed to use the "unrequested funds" for the implementation of the AB 841 School EE Stimulus Schools Program. *See* D.21-01-004, *Decision Providing Directions for Implementation of School Energy Efficiency Stimulus Program*, at p. 8 as approved under R.13-11-005. Hence, these funds remain available for use by MCE.

- Creating a program infrastructure that delivers market-driven results, without prescriptive customer incentives, and allows aggregators to determine the most cost-effective methods of generating impacts; and
- Integration with existing EE programs to ensure that opportunities to upsell flexible equipment are not lost opportunities.

The most significant risks to the *Peak FLEXmarket* are:

- Auto-enrollment program designs, which would effectively block large subsets of MCE's customer base from enrolling in new or alternate demand flexibility programming;[30]
- A confusing statewide market for DR, where the value of demand flexibility may vary widely depending on which LSE or entity is administering a program, and the method of measurement; and
- Confidence among aggregators that the *Peak FLEXmarket* model will continue with reliable, sufficient funding in place. A limited budget and/or uncertainty in the *Peak FLEXmarket*'s continuation will impact aggregators' interest in investing time, resources and project enrollments. Even if the customer value proposition is stronger, the market will gravitate toward program and investment opportunities viewed as stable to mitigate risk.

MCE therefore recommends that the Commission provide as much clarity to the market as possible, with consistent price signals. Also, to scale DR as a reliability resource, it is critical that the solutions bring significant *customer* benefits. This is best accomplished by integrating EE or

[30] *See*, *infra*, Chapter 3, Section B, for discussion of barriers created by automatic enrollment designs.

demand management opportunities that reach beyond Flex Alerts and generate customer savings on a regular basis, not just when the grid needs them to be responsive.

2. MCE's *Energy Storage Program*

The Amended Scoping Memo specifically identifies virtual power plants ("VPPs"), or DER export, as resources that are capable of reducing demand (or net demand) and thus expressly included within the scope of this Proceeding.[31] As detailed below, MCE is running an *Energy Storage Program* that launched in July of 2020. Under the *Energy Storage Program*, MCE is able to control the ESS of residential and non-residential customers to align charging and discharging behavior with grid needs and to reduce demand during times of grid stress. Hence, the program is a perfect fit for consideration as a new demand flexibility program to meet the State's grid reliability needs.

While the initial focus of the *Energy Storage Program* has been on increasing customer resilience in the face of Public Safety Power Shutoffs ("PSPS"), MCE could expand the use cases under the program to also include demand flexibility strategies. In the following proposal, MCE describes the current program design and MCE's recommendations on how to grow and modify the *Energy Storage Program* to meet the State's demand reduction goals.

a. General Program Design

MCE's *Energy Storage Program* offers compensation to participating customers (both residential and non-residential) in exchange for allowing MCE to directly monitor and control their ESS using a Distributed Energy Resources Management System ("DERMS") software platform. Under the program, MCE automatically charges participants' ESS from solar PV, then discharges them every day between 4pm to 9pm. These systems are aggregated into a VPP and can also be

[31] Phase 2 Scoping Memo, p. 5.

manually and automatically dispatched in response to a CAISO signal for emergency load reduction. In exchange for agreeing to allow MCE to dispatch the ESS, customers are provided with different types of up-front and performance-based incentives to lower the cost of the ESS. Before the end of this year, MCE will launch a loan program that will offer zero and below-market interest rates to customers needing to finance their systems. While the MCE *Energy Storage Program* is available to any MCE generation service customers, the program provides increased incentives and has a participation goal for low-income or other vulnerable customer categories.

i. Program trigger

The *Energy Storage Program*'s main goal, as currently designed, is to achieve *daily* load shifts during the evening peak period. To achieve this goal, the DERMS platform automatically charges each ESS from the co-located solar PV each day until fully charged. Then, each day, the ESS are discharged during the evening peak period from 4pm-9pm (or 3pm-8pm, or 5pm-9pm, depending on the tariff and season). This happens automatically, 365 days per year, unless (1) a customer manually opts-out of a dispatch command, (2) MCE manually discharges the ESS for another purpose (*e.g.*, an emergency load reduction request from the CAISO), or (3) in the event of a planned or unplanned outage. In the case of a planned PSPS event, MCE's software platform will charge the ESS to 100% 24-hours in advance of the planned shut off and hold the state of charge ("SOC") at 100% until the outage begins. Once power is restored, the ESS will resume daily peak load reductions.

Most relevant to this Rulemaking, MCE could incorporate the capability in the DERMS platform to manually schedule events to discharge the ESS during "event days" or in response to emergency load reduction requests from the CAISO (*i.e.*, the "DR Use Case"). MCE envisions that DR events would be triggered by the CAISO's AWE process, similar to other emergency DR programs.

Under the DR Use Case, MCE envisions two participation pathways. First, with day-ahead ("DA") notifications, MCE develops the capability of discharging ESS starting at a set time for a given number of hours down to the ESS's reserve SOC, defaulted to 20% for all customers in the program. Second, MCE develops the capability for Day-Of ("DO") notifications to discharge batteries; however, DO events may be limited by the ESS' available SOC if the ESS has not charged to 100% from co-located solar at the time the event is called.

To incorporate the DR Use Case into MCE's *Energy Storage Program*, MCE requests additional funding from the Commission to work with both existing and new vendors to deploy these use cases, and to discharge customer-owned ESS more frequently.

ii. Demonstration that program will deliver benefits during net peak

All ESS will be directly monitored and controlled by MCE's DERMS platform. This software platform stores information about the batteries' SOC and all charging and discharging events. Using this platform, MCE will have a precise record of all kWh charged and discharged, recorded at 5-minute intervals. MCE can provide data for all kWh discharged from ESS enrolled in its program for the summer period, if required.

iii. Program performance requirements

All customers participating in MCE's *Energy Storage Program* must either have existing solar PV or agree to install solar with new batteries. Currently, customers must own their ESS and must allow MCE to monitor and control their systems via its DERMS platform to receive performance-based payments and bill credits. Qualifying ESS must be capable of being controlled by MCE's DERMS platform through an OpenADR2.0b certified virtual end node ("VEN"), and capable of providing telemetry to MCE at 5-minute intervals. Customers also agree to maintain a 20% reserve SOC, effectively allowing MCE to control 80% of the usable capacity of a battery.

iv. Compensation structure

MCE currently offers customers an upfront payment to decrease the initial cost of the ESS. Incentives to cover this upfront battery cost range from \$100/kWh to \$300/kWh, depending on customer qualifications. For example, MCE offers different upfront incentives based on whether a customer qualifies as low-income (CARE/FERA or 80% Area Median Income) or vulnerable (medical necessity, located in a disadvantaged community ("DAC") or Low-Income Community, located in a High Fire Threat District ("HFTD") Tier 2 or 3, experienced 2+ PSPS events, relies on electric well pump).

In addition to the upfront incentives, and to compensate customers for allowing continued control of the battery, MCE currently provides residential customers with a \$10-\$20/month bill credit depending on the size of the system. For non-residential customers, the monthly bill credit is \$20 for each 20kWh of energy storage, up to \$200/month. Non-residential customers also qualify for a performance-based payment at \$0.22/kWh for every kWh discharged by MCE during the 4pm-9pm daily peak.

The *Energy Storage Program*'s existing payment structure, as described above, is based on the daily load shift use case. If MCE's funding request is approved, MCE proposes to also compensate customers for discharge during DA and DO events triggered by the CAISO AWE process. Event participation would be compensated at DA or DO market prices with a price floor of \$200/MWh discharged from participating ESS's. Where feasible, MCE may add additional event triggers with compensation set to align with other DR programs.

v. Program eligibility and enrollment

To be eligible for participation under MCE's *Energy Storage Program*, customers must own the ESS and must have existing solar PV or agree to install solar with the new ESS. Residential customers must own their home or have permission from the homeowner to install the

ESS. Currently, residential customer participation is limited to single-family homes or small (less than 5 unit) multi-family homes that are individually metered and have individual solar PV systems installed. Any non-residential customer can participate if they have existing solar PV or agree to install solar with the ESS. All participants must agree to allow MCE to control the ESS, except during outages, via MCE's DERMS software platform. All developers/Trade Allies[32] must agree to use OpenADR 2.0B open access communications protocol and agree to MCE control and performance requirements.

MCE is targeting 50% participation from low-income or other vulnerable customer categories.[33] MCE is using a third-party implementer to manage customer enrollment via selected developers and Trade Allies.

vi. Measurement and verification, if needed

MCE's DERMS platform monitors and records 5-minute interval data, including battery SOC and charge/discharge events. The system tracks individual customer system performance data and aggregated VPP performance data. Systems can be individually dispatched, or controlled by circuit, city, county or other groupings as determined by MCE.

b. Program Administration

MCE is the program administrator of the *Energy Storage Program* and has hired a third-party to implement the program. The program implementer is responsible for overseeing the customer enrollment process, managing Trade Allies, developers and vendors, software setup and

[32] Trade Allies are partner-vendors that agree to meet administrative and technical requirements and participate in the Program and are approved by MCE and its Program Implementer to work with MCE customers.

[33] "Vulnerable customers" are defined as those customers living in Disadvantaged Communities ("DACs"), designated Low-Income Communities, or those with a medical need, living in a Tier 2 or 3 High Fire Threat District ("HFTD"), or who have experienced two or more PSPS events. Included in this customer base are government and nonprofit organizations that provide essential services to vulnerable communities.

integration, program optimization, quality assurance/quality control, program evaluation, and technical support.

c. Program marketing, outreach and education

MCE is responsible for customer awareness and customer lead generation and maintains a customer-facing intake form on its website. The developers, working with the program implementer, contact customers to set up site visits, provide cost and savings estimates, and enroll customers into the program. MCE oversees and approves all ME&O materials and activities. Customers targeted for outreach include large solar exporters, customers with high usage during peak hours, and customers with high ramp rates between off-peak and peak hours. MCE proposes funding ongoing education and outreach to program participants to increase awareness of event-based use cases and program triggers based on the CAISO AWE process.

d. Program budget

MCE funded the development and launch of the *Energy Storage Program* through its ratepayer generation revenues. With access to additional funding, however, MCE expects to be able to expand the program and support the development of additional use cases and optimization of the VPP. As such, MCE requests the approval of $4,408,000 in program funding. This budget is largely driven by one-time incentives to support the deployment of ESSs and ongoing customer incentives for deploying additional use cases. Table 2 below details MCE's budget proposal to expand the *Energy Storage Program* to include a DR Use Case and to enroll additional customers in years 2022 and 2023.

Table 2: *Energy Storage Program* Budget Proposal for PY 2022 and 2023.

#	Budget Line Item	Cost ($)
1.	**Program Administration**	**$740,000**
1.1	Start-up costs	$240,000
1.2	Ongoing admin costs	$500,000
2.	**Customer Incentives**	**$3,468,000**
3.	**Marketing, Education and Outreach (ME&O)**	**$100,000**
4.	**Evaluation, Measurement and Verification (EM&V)**	**$100,000**
	TOTAL	**$4,408,000**

- Program Administration

As with *Peak FLEXmarket*, a key advantage to leveraging the *Energy Storage Program* is that the majority of one-time program start-up costs have already been funded through MCE's generation revenues, and that, as an already-existing program, it can quickly scale to achieve additional load reductions in 2022 and 2023. The limited remaining start-up costs for continued support and growth of the program in PYs 2022 and 2023 include the following activities and budget forecasts:

- Support the integration of 2 additional vendors' ESS with MCE's DERMS platform through an OpenADR2.0b VEN;
- Incorporate DA and DO event notification capability in response to CAISO AWE process under MCE's DERMS platform;
- DERMS SaaS license fees for expanding functionality and support through April, 2023.

Ongoing administrative costs for PYs 2022 and 2023 include:

- Contracted services for a program implementer to support pipeline management, case management, and customer project management;
- MCE internal staffing support for program administration and implementation.

Resources installed under this program will continue to operate and provide load flexibility for many years. After the initial customer enrollment, installation, and activation process is complete, MCE forecasts ongoing administrative costs beyond 2023 to be modest (less than 10% of total program costs).

<u>2. Customer incentive payments</u>

Customer incentive payments for PYs 2022 and 2023 are estimated based on:

- One-time customer incentives to expand enrolled ESS capacity controlled by the DERMS platform, offering incentives between $0.10 and $0.30 W/h based on customer type;
- Expanded monthly performance-based incentives for event-based participation at $200/MWh - $800/MWh discharged by the ESS.

In addition to the above-requested funds for customer incentive payments, MCE will continue to fund the monthly bill credit and performance-based payments to non-residential customers for daily load shift from its own generation revenues.

<u>3. ME&O</u>

MCE markets qualifying ESS to customers with existing Solar PV and conducts joint marketing with Trade Allies to engage customers that plan to install SolarPV and new storage.

MCE proposes funding ongoing education and outreach to *Energy Storage Program* participants on the proposed event-based use cases and additional dispatches under this proposal.[34]

4. Measurement and Verification ("M&V")

M&V costs entail contract services for data collection and program evaluation. The MCE DERMS platform will function as the data warehouse to collect real-time telemetry from program participants and is capable of reporting actual charge, discharge, and customer opt-out rates in response to event notifications.

e. Implementation timeline

As with *Peak FLEXmarket*, MCE's *Energy Storage Program* is already up and running and can be readily leveraged for increased demand reductions beginning in June 2022. These programs therefore present the Commission with an opportunity to capture a low-hanging fruit opportunity for demand reduction in 2022, since minimal additional work is needed to quickly scale the program.

Initial customer enrollment for the *Energy Storage Program* began in the summer of 2020 and the first installation was completed in late 2020. The DERMS platform will be operational in the 4th quarter of 2021, when MCE expects to begin dispatching systems for daily peak load reduction. As soon as the Commission grants MCE access to ratepayer funds to expand the Energy Storage Program under this proposal, MCE will develop the DA and DO notification capability and optimize the dispatch of the VPP for CAISO AWE events.

[34] *See* https://www.mcecleanenergy.org/smart-energy-practices/ and https://www.mcecleanenergy.org/experts/ for examples of existing collateral targeted at daily load shifting and energy usage.

f. Program duration

Residential customers participating in the program must sign a five-year agreement for MCE control over the ESS, beginning when the system receives a Permission to Operate ("PTO"). Nonresidential customer agreements have a seven-year term, also beginning when the system receives a PTO. MCE may consider extending the term of the customers' agreements if the program proves successful in reducing peak demand and associated costs, and given sufficient customer interest. It is also important to note that the resources enrolled under the program will continue to provide load reductions long after the terms of the agreement with MCE are over, especially if the customer has become "energy aware", *i.e.*, they have learned how to appropriately use the ESS to reduce load at times when prices are high.

g. Estimated megawatt contribution/load impact

As previously mentioned, MCE only began enrolling customers in its *Energy Storage Program* in the summer of last year and currently only has a handful of customers whose system has received a PTO from PG&E. However, MCE expects to have at least another 80 to 100 residential ESS installations to be completed in late 2021. Due to the greater complexity and longer development time required, MCE expects to have the first non-residential installations completed in early 2022. Hence, MCE cannot yet report on achieved load reductions under the program.

Based on the current program pipeline and including the additional funding requested in this testimony, MCE forecasts an installed capacity of 13.4 MWh (3.36 MW) and a net peak reduction of 2.05 MW by June 1, 2022. By June 1 2023, MCE is projecting 25 MWh (6.27 MW) of installed capacity and a projected net peak reduction of approximately 3.82 MW, depending on the timing and duration of the event, and the SOC of the batteries.

If the Commission allows for exports from the ESS, particularly for systems larger than 10 kW, MCE believes it may be able to achieve greater reductions more quickly. Larger commercial and industrial customers who close or cease operations at 5pm may have a significant amount of unused capacity still left in the ESS that could be tapped to reduce the system peak if allowed to export that energy.

MCE does not expect that the load impact under MCE's *Energy Storage Program* would reduce the impact of any existing programs as the participating customers (*i.e.*, customers that own solar PV + ESS systems) are traditionally not customers who have participated in existing DR programs. MCE's DERMS platform will also collect charge and discharge data and record other telemetry from participating customers to verify that there is minimal impact to existing programs.

h. Potential interaction with other existing programs (i.e., dual participation issues)

MCE does not expect there to be any interaction between the *Energy Storage Program* and other DR programs at this time. Residential customers targeted for this program have not traditionally participated in other DR programs. Non-Residential customers, upon enrollment, will be screened for participation in other DR programs, and load impacts attributable to participation in the *Energy Storage Program* can be assessed using the real-time telemetry collected by the DERMS.

i. Prior similar program experience in California or elsewhere

Not applicable.

j. Program funding and cost recovery mechanisms

MCE requests that the Commission authorize $4,408,000 of ratepayer funds for MCE to scale its *Energy Storage Program* to achieve additional net peak demand reduction during the summers of 2022 and 2023.

To expand on the *Energy Storage Program*, MCE recommends that the Commission authorize MCE access to the same ratepayer-funds to be allocated to other program proposals authorized under Phase 2 of this Rulemaking.

k. Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk

As previously stated, the *Energy Storage Program* presents a low-risk opportunity for ratepayer funding given that MCE has already undertaken the majority of the program's startup costs and has already attracted customer enrollment.

Still, MCE recognizes that growing this type of energy storage program, just like any device-enabled program, does not happen quickly because of the lengthy lead times for new solar and storage system installations and interconnection. Therefore, while the *Energy Storage Program* provides an excellent opportunity for load reduction with currently participating customers or those in the program that are already going through the installation process,[35] any ESS load reductions from devices not yet installed or recruited will likely not be available to achieve load reductions during the summer of 2022. Nevertheless, new resources recruited in early 2022 could still deliver peak demand reduction opportunities for PY 2023. Interest in installing ESS remains strong despite the long lead times, with customers continuing to express interest in the program through the program's interest forms.

There could also be delays for permitting,[36] installing and interconnecting ESS. MCE has encountered these issues during the current program rollout and hence believe that these issues could persist into the future. These include supply chain shortages for batteries, equipment, and

[35] MCE currently has over ninety customers in the program pipeline.
[36] Permitting delays can be mitigated by supporting permit streamlining initiatives; the CEC has funded a multi-year grant to create a statewide storage permitting guidebook and support the deployment of permit streamlining software.

raw materials due to the COVID-19 pandemic, delays in permitting and inspecting ESS, and delays in receiving a PTO once the system is installed and inspected. In addition to the pandemic-related delays, the demand for energy storage has been increasing due in large part to the increasing frequency, extent and severity of wildfires in the state and related PSPS events. This increased demand could also cause delays in reviewing and approving applications for the Self-Generation Incentive Program ("SGIP"), a major driver for the installation of customer-sited ESS in California.

3. EV Charging Load Management Program ("*MCEv Sync*")

The Amended Scoping Memo also contemplates that EV infrastructure may prove a valuable DR or load management tool that can be considered or expanded in this Rulemaking.[37] MCE agrees, and has been developing a self-funded residential EV charging program, called "*MCEv Sync*" in collaboration with its implementation partner ev.energy. The program allows MCE to control EV charging behaviors of enrolled customers in furtherance of the load reduction and grid resiliency goals espoused in the Emergency Proclamation and considered under this Rulemaking. Therefore, the program is a natural fit for expansion under this Rulemaking.

a. General Program Design

Under the *MCEv Sync* program, MCE and ev.energy will enroll 200 MCE customers who charge their EVs at home into the ev.energy platform, which delivers direct load control over their EV charging using vehicle telematics and networked electric vehicle supply equipment ("EVSE"). The initial aim of this program is to deliver regular load shifting away from the 4pm - 9pm peak window, while aligning as much EV charging as possible with high-solar daytime hours. In doing

[37] Phase 2 Scoping Memo, p. 5.

so, MCE can harness the flexibility of many MCE customers continuing to work from home. Even before the pandemic, approximately 80% of residential charging occurred at home.

The pilot is currently scheduled to start in September 2021 and conclude in March 2022. Under this proposal, MCE proposes to extend the pilot through the end of 2023, while expanding it from the 200-customer cohort to enroll 2,500 EV drivers by June 2022 and 5,000 EV drivers by June 2023. MCE's service area has one of the highest EV adoption rates in the state with over 43,000 EVs currently registered, providing ample opportunity for high adoption of the *MCEv Sync* program.

i. Program trigger

The *MCEv Sync* pilot was initially developed to deliver *daily* load shifting away from the 4-9pm peak window. With additional funding, MCE proposes to add a secondary use case under the program which focuses on delivering peak load shaving benefits during time-bound events called by CAISO (*i.e.*, event-based participation). More specifically, MCE customers enrolled in this program will have their charging curtailed/shifted in response to CAISO's AWE process. MCE will deliver push notifications to customers' mobile phones via the *MCEv Sync* app to alert them of these events and will reward customers for their automatic participation (*i.e.*, not "opting out" of an event) through performance-based incentives.

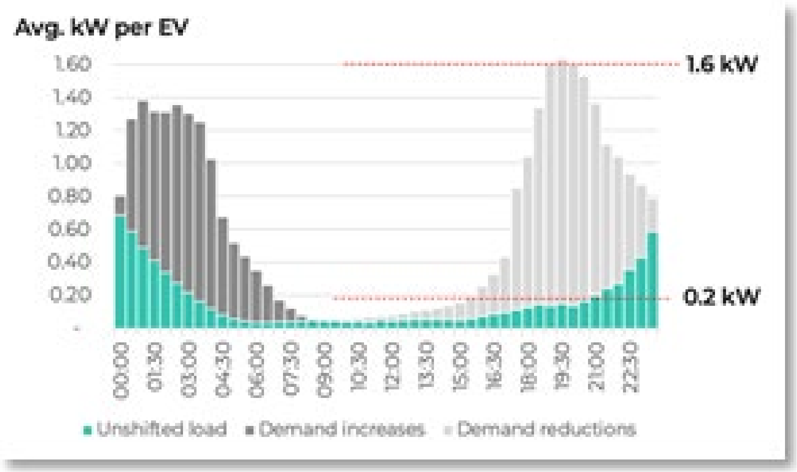
ii. Demonstration that program will deliver benefits during net peak

CCAs across California and utilities across the U.S. rely on ev.energy's software[38] to deliver peak load shaving and load shifting for residential EVs. More specifically, ev.energy has proved its ability to shave peak EV load by aggregating and managing the charging of thousands

[38] *See* ev.energy list of partners, *accessible at* https://ev.energy/.

of EV drivers, shaving about 1.4kW of load per EV during the 4pm-9pm window, as shown in Figure 1, below.

Figure 1. ev.energy Peak Load Shaving Experience[39]



Because nearly 80% of MCE's residential customers are enrolled in flat rates (*e.g.*, the residential base rate E1), they are not financially incentivized to charge their EVs outside of the 4pm-9pm net peak window. The remaining 20% of residential customers on time-of-use ("TOU") rates might still set vehicle timers that cause incident peaks before or after the 4-9pm net peak window.

The *MCEv Sync* program, however, will aggregate thousands of EVs across MCE's four-county service area and actively manage customer charging to shift EV loads outside of the net peak window and distribute them throughout the system's off-peak hours to avoid any incident or rebound peaks.

[39] This figure shows shifted and unshifted load in ev.energy's Texas VPP, which offered a case study of a similar program to provide emergency grid services in Texas. As described by ev.energy, the light grey bars represent scheduled EV charging that was shifted outside of ERCOT Emergency Response Service event windows, to the dark grey bars. Blue bars on the bottom represent unshifted load due to customers opting out of the event to continue charging. On average, ev.energy is able to curtail 1.4 kW of load per vehicle in Texas. *See* https://ev.energy/ev-energy-ercot/

iii. Program performance requirements

Each participating customer will need to have managed charging enabled in the *MCEv Sync* app and have at least 70% of their at-home EV charging (in kWh) controlled by ev.energy. In exchange, customers will receive a participation incentive of $10 per month in which they are eligible. There will be no penalties for non-participation.

iv. Compensation structure

MCE proposes the following compensation structure for eligible MCE residential customers who drive EVs:

- Upfront incentive: An $50 one-time upfront program enrollment incentive; and
- Monthly participation credit: $10 per month of participation in which at least 70% of the customer's charging is managed by ev.energy on a daily basis (*i.e.*, the customer does not opt out of managed charging for more than 30% of kWh in a given month).

Over a 24-month program, the most a customer could earn would be $290 in incentives. The incentives will be paid out monthly to the customer.

v. Program eligibility and enrollment

Both bundled and unbundled customers are eligible so long as they meet the following eligibility criteria to enroll in this program:

- Customers must do the majority of their EV charging (*i.e.*, 70%) at their residential address;
- Customers may not be enrolled in another DR program; and

- Customers must either drive a compatible EV[40] or have a compatible networked EVSE installed in their home.[41]

Customers register their interest in a sign-up form on a web page hosted by MCE that outlines the program benefits and eligibility criteria. Once customer eligibility has been verified, the customer will receive an email with instructions on how to download the *MCEv Sync* app and enroll in the program by agreeing to program terms, connecting their vehicle or charger, and enabling managed charging within the app.

vi. Measurement & Verification

The program's measurement and verification ("M&V") will establish a control group of EV drivers similar in composition to the program participants whose EV charging is not being managed by MCEv Sync. MCE will analyze both control group and treatment group charging loads and patterns to calculate the load shifting and peak load shaving impact of the *MCEv Sync* program.

b. Program Administration

MCE will administer the program in collaboration with its implementation partner ev.energy. With support from MCE, ev.energy will lead on marketing and customer recruitment and deliver front-line telephone and email support for customers. ev.energy will also build, publish and maintain the Application Program Interfaces ("APIs"), the managed charging platform, and the mobile app needed to deliver peak load reduction and enable customer participation. Finally,

[40] Currently, compatible EVs include: Tesla, Volkswagen, Chevrolet, Jaguar and Land Rover – and Ford and Nissan will be added by December 2022.
[41] Compatible EVSE currently includes: ChargePoint, Siemens and SmartenIt – and the addition of EnelX and Flo by June 2022.

ev.energy will calculate monthly participation incentives based on measured load reductions from the vehicle and charging telematics within the app.

c. Program Marketing, Education and Outreach

MCE and ev.energy will work closely together to promote the *MCEv Sync* program and its benefits to maximize enrollment figures, with an eye toward social equity and inclusion of lower-income customers in the program. MCE will use this opportunity to promote the benefits of EV adoption, including lower total cost of ownership for customers and cleaner air for communities. MCE will also educate customers on energy consumption and how they can shift their EV charging schedules and habits to support the reliability of the California grid.

More specifically, MCE and ev.energy will work together to market the program and enroll customers via the following channels:

- Emails to known EV drivers (customers enrolled in EV rates, customers participating in MCE's EV Rebate Program);[42]
- Emails to likely EV drivers via ev.energy's Original Equipment Manufacturer ("OEM") partnerships (*e.g.*, Tesla and VW dealerships, ChargePoint and Siemens EVSE distribution channels);
- Partnerships with local EVSE installer networks like QMerit and SmartCharge America;
- Outreach to local community-based organizations ("CBOs") through MCE's Community Power Coalition, Ride and Drive Clean, local Electric Auto Associations, and other EV clubs; and
- Social media campaigns targeting likely EV drivers within MCE's service area.

[42] MCE's EV Rebate Program is *available at* https://www.mcecleanenergy.org/ev-drivers.

d. Program Budget

To date, MCE has funded the development of the *MCEv Sync* program through its generation revenues. As noted above, the program is currently slated to conclude in March 2022. However, with access to additional funding, MCE could extend the program through the end of 2023, while expanding it from the current 200-customer cohort to enroll 2,500 EV drivers by June 2022 and 5,000 EV drivers by June 2023. Table 3 below details MCE's budget proposal to expand *MCEv Sync* to include a DR Use Case and to enroll additional customers in years 2022 and 2023.

Table 3. *MCEv Sync* Budget Proposal for Expansion through 2023.

#	Budget Line Item	Cost ($)
1.	**Program Administration**	**$726,000**
1.1	Start-up costs	$150,000
1.2	Ongoing admin costs	$576,000
2.	**Customer Incentives**	**$840,000**
3.	**Marketing, Education and Outreach (ME&O)**	**$120,000**
4.	**Measurement and Verification (M&V)**	**$75,000**
	TOTAL	**$1,761,000**

1. Program administration costs

Program administration fees include start-up and ongoing costs for MCE and ev.energy to develop and implement the pilot program. It must be noted that the large majority of upfront costs has already been paid by MCE through its own ratepayer revenues as the program is expected to launch in September 2021. The remaining start-up costs are all related to expanding the use cases under the program to also include an event-based participation model. Remaining one-time start-up costs include:

f. Integration of ev.energy platform with CAISO AWE process;

g. Updates to MCEv Sync app to support summer demand response incl. customer alerts;

h. Nissan and Ford vehicle telematics APIs to enable broader program eligibility and expansion; and

i. Enel X and Flo charger APIs to enable broader program eligibility and expansion.

Ongoing administrative costs for 2022 and 2023 include:

j. ev.energy software fees;

k. ev.energy administration and customer support fees; and

l. MCE program administration costs.

<u>2. Customer Incentives</u>

Customer incentives are composed of two different payment streams: upfront enrollment incentive and monthly participation credits as described in section 3.a.iii above.

<u>3. ME&O costs</u>

MCE is deploying an omni-channel marketing and customer recruitment campaigns across email, digital, print and community organizations. This ME&O will result in the recruitment of 4,800 additional customers, with an average customer acquisition cost of $25.

<u>4. M&V costs</u>

MCE budgets $75,000 for M&V under the program.

e. Implementation timeline

To deliver demand reduction in time for June 2022, this program will leverage the ongoing 200-customer *MCEv Sync* program, set to end in March 2022, and extend it through the end of 2023. Since the *MCEv Sync* app has already been built and much of the infrastructure is in place, MCE and ev.energy will be able to focus their efforts on program expansion as soon as the Commission approves this proposal, with a target of 2,500 customers enrolled by June 2022 (a fraction of the 43,000 EVs currently registered in MCE's service area).

Between June and October 2022, the program will deliver EV load curtailment and load shifting in line with dispatch signals sent by CAISO and/or MCE's proprietary DERMS platform, targeting 2.5 MW of peak load reduction.

From October 2022 until May 2023, the program will focus on (1) evaluation and verification of results from summer 2022; (2) recruitment of an additional 2,500 customers to reach the 5,000-customer target by June 2023; and (3) optimization of customers' EV charging for hours of high grid solar generation, in order to shift as much flexible demand as possible to the belly of the duck curve.

Between June 2023 and October 2023, the program will deliver EV load curtailment and load shifting in line with dispatch signals sent by CAISO and/or MCE's proprietary DERMS platform, targeting up to 5 MW of peak load reduction. M&V of results from summer 2023 will wrap up in November and December of 2023.

f. Program Duration

The *MCEv Sync* program is currently scheduled to launch in September 2021 and run through March 2022. If the Commission approves MCE's funding request described herein, program enrollment could be expanded and the duration of the program extended through 2023 or as desired by the Commission and other stakeholders.

g. Estimated MW contribution/load impact

With thousands of EVs on its platform, ev.energy has proven its ability to reduce demand at peak hours between 4pm and 9pm, at a level of 40pprox.. 1.4 kW of load per EV in its VPP.[43] This portfolio-level average accounts for the fact that while residential Evs tend to charge at around 10-11 kW, not every EV is plugged in and charging at any given time, and so roughly 10% of the VPP can be dispatched to deliver peak load reduction when required.

On this basis, MCE expects the program to contribute 2.5 MW in peak load reduction during Summer 2022 and 5 MW during Summer 2023. To achieve this goal, MCE plans to enroll 2,500 Evs by Summer 2022 and 5,000 Evs by Summer 2023. Each participating EV will need to deliver ~ 1kW of peak load reduction on average. MCE believes that this is a realistic forecast given that most Evs charging on L2 consume ~10kW of power; so the average EV would need to be plugged in and charging only 10% of the time.

The above load impacts are based on submetered EV load obtained, using vehicle telematics or revenue-grade charging data from the EVSE. They do not account for other sources of household load which could net out any load reduction at the meter level. For example, EV charging is curtailed during a given period but a customer runs a portable air conditioner, a pool pump, or a tumble dryer within the house. At the household meter level, it may appear that little to no load reduction has been delivered, which is why our M&V plans will use submetered EV data to accurately measure the system benefits that have been delivered.

h. Dual participation issues

As stated above in the customer eligibility and enrollment section, MCE does not allow customers to participate in the *MCEv Sync* program if the customer is already enrolled in another

[43] *See* ev.energy case study of its VPP in Texas, *accessible at* https://ev.energy/ev-energy-ercot/.

DR program. MCE and ev.energy will work with the customer to either unenroll the customer from the existing DR program or will not allow the customer to enroll under the *MCEv Sync* program.

i. Prior similar experience in California or elsewhere

Silicon Valley Clean Energy ("SVCE") runs a similar residential EV charging program administered by ev.energy called SVCE GridShift.[44] EV drivers enroll in this program via a mobile app similar to *MCEv Sync*, which manages SVCE customers' charging during the summer months to shift/curtail load during CAISO FlexAlerts and ELRP dispatches. After an initial pilot,[45] SVCE's GridShift program has scaled up to ~1,000 EV drivers and continues to grow through sustained marketing efforts. GridShift's ability to deliver load-shifting and curtailment outside of the 4pm-9pm window has been verified by a third-party M&V firm, ADM Associates.

In addition, ev.energy built a VPP of EVs in Texas, which provides DR services to ERCOT year-round via the Emergency Response Service. This VPP currently stands at approximately 500 EVs providing 0.5 MW of load curtailment during the 7pm-10pm Standard Contract Term.[46] EV drivers are engaged and incentivized via the ev.energy mobile app.

j. Program funding and cost recovery mechanism

MCE requests that the Commission authorize $1,776,000 of ratepayer funds for MCE to scale its *MCEv Sync* Program to achieve additional net peak demand reduction during the summers of 2022 and 2023.

[44] *See* https://www.svcleanenergy.org/gridshift-ev/.
[45] https://www.svcleanenergy.org/wp-content/uploads/2020/02/2021-Q1-Programs-Update-compressed.pdf
[46] *See* ev.energy case study of its VPP in Texas, accessible at https://ev.energy/ev-energy-ercot/

To expand on the *MCEv Sync Program*, MCE recommends that the Commission authorize MCE access to the same ratepayer-funds to be allocated to other program proposals authorized under Phase 2 of this Rulemaking.

k. Potential risks of proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk

As with MCE's other program proposals, *MCEv Sync* presents a low-risk opportunity for ratepayer funding given that MCE has already undertaken significant program startup costs and has already attracted customer enrollment.

III. CONCLUSION

For the reasons stated above, MCE requests that the Commission authorize ratepayer funding to scale these three programs, which present a low-hanging fruit opportunity to achieve demand reductions in time for summers 2022 and 2023 in a cost-effective manner for ratepayers.

Specifically, MCE requests funding authorization as follows:

(1) $11,560,000 to expand upon the success of its *Peak FLEXmarket* program;

(2) $4,408,000 to leverage MCE's *Energy Storage Program*; and

(3) $1,776,000 to leverage MCE's pilot EV charging program, *MCEv Sync*.

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CHAPTER THREE

COMMENTS ON STAFF CONCEPT PAPER

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CHAPTER THREE
COMMENTS ON STAFF CONCEPT PAPER

TABLE OF CONTENTS

I. INTRODUCTION

MCE appreciates the significant efforts that staff of the Commission's Energy Division ("ED Staff") have put into the Staff Concept Paper, particularly on such a short timeline, to identify opportunities for demand reductions in the summers of 2022 and 2023. MCE submits, however, that the following modifications to the Staff Concept Paper are critical to achieving the goals of the Emergency Proclamation and a sustainable energy future for Californians:

(1) include CCAs as a key partner in demand flexibility programming and reject any policies that will have an anti-competitive impact by favoring IOU (or third-party) DR programs;

(2) avoid auto-enrollment program designs that limit customer choice and market-driven opportunities;

(3) facilitate data exchange between IOUs and CCAs on DR program participation; and

(4) adopt smart control thermostat ("SCT") incentives that are consistent with the overall aim of achieving load reduction.

A. CCAs Must be Recognized as Key Partners in Demand Flexibility Programming.

The Staff Concept Paper largely turns a blind eye to non-IOU DR programs and instead proposes program modifications that, if adopted, would significantly curtail load-reduction initiatives being pursued and actively deployed by non-IOU DR providers. The Commission should reject any such proposals as contrary to its longstanding policy to encourage customer choice, and also in conflict with the goal of rapidly achieving grid reliability enhancements for summer 2022 and 2023.[47]

[47] *See, e.g.*, D.16-09-056, p. 52 ("Utilities and third-party providers should fairly compete on a level playing field to vie for customers to enroll in their demand response programs."); D.12-12-036, at p. 2 (stating the importance that CCAs have "the opportunity to compete on a fair and equal basis with other load-serving entities.")

Instead, Commission policies should recognize that CCAs are LSEs with an important role to play in fostering DR program expansion and customer participation. CCAs are in the process of, or have already developed, various DR programs and the Commission cannot minimize the important role that CCAs can play as program administrators of new DR programs. As MCE's experience shows, CCAs are nimble organizations capable of launching new programs with relative speed.[48] CCAs are also local organizations that uniquely understand their customers' needs, which means that CCAs can tailor DR programs to scale customer engagement and maximize load impact. Further, unlike IOUs, which have a strong capital bias, the mission of CCAs is squarely aligned with reducing peak demand, emissions avoidance, and lower customer costs.

Hence, the Commission should include CCAs as a key partner in demand flexibility programming and reject any policies that will have an anti-competitive impact by favoring IOU (or third-party) DR programs, as further elaborated below.

B. Avoid an Auto-Enrollment Program Model for DR Programs

The Staff Concept Paper proposes several modifications to the IOU-run Emergency Load Reduction Program ("ELRP").[49] Most concerningly, Staff propose to automatically enroll *all* residential customers not currently enrolled in a supply-side DR program into ELRP.[50] As explained in comments submitted by parties in response to the Phase I proposals submitted by Pacific Gas & Electric's ("PG&E") and the California Environmental Justice Alliance ("CEJA"),[51]

[48] For example, MCE designed, developed and launched the Peak FLEXmarket program within 3 months in the spring of 2021.

[49] ELRP is a five-year DR pilot program established by Decision ("D.") 20-11-003 and run by IOUs. ELRP operates when the California Independent System Operator ("CAISO") issues a Grid Alert, Warning or Emergency. Both residential customers and non-residential customers are eligible to participate, but only non-residential customers are compensated for load reduction under the program.

[50] Staff Concept Paper, p. 5.

[51] See Prepared Supplemental Reply Testimony of Dan Skaguchi on behalf of CEJA, June 14, 2021; PG&E Supplemental Testimony, July 7, 2021.

any such automatic enrollment program design would create a significant market barrier to DR program development, cause increased customer confusion, have a limiting effect on the potential load reduction impact for certain customer segments, and discriminate against non-IOU DR providers.[52] MCE thus strongly encourages the Commission to reject any such automatic enrollment model.

It is particularly important that CCA generation service (or "unbundled") customers are not automatically enrolled into an IOU DR program since, under the dual-participation rules found in the IOU tariffs, any participant that enrolls in an IOU DR program is barred from enrolling in any other DR program, including CCA DR programs.[53] As described in Chapter 2 above, MCE already offers a variety of demand flexibility programs to customers within MCE's service area; hence, the auto-enrollment provisions proposed in the Staff Concept Paper present a real and immediate threat to the continued growth and success of MCE's demand flexibility programs.

The Staff Concept Paper accurately observes that ELRP suffers from low customer participation and low overall program effectiveness.[54] But MCE strongly discourages the Commission from taking the counterintuitive approach of "doubling down" on a lackluster program by automatically enrolling large swaths of customers, especially when there are alternatives—such as the MCE demand flexibility programs described in Chapter 2—that show significant promise in attracting diverse, expansive participation that can scale.

And while the Staff Concept Paper contemplates that "IOUs and third-party DR Providers would still be permitted to target Residential ELRP customers to enroll them into their respective

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[52] *See, e.g.,* Reply Testimony of OhmConnect, Inc., (July 21, 2021), pp. 3-9 (hereinafter, "OhmConnect Reply Comments"; SDG&E Opening Flex-Alert-CPP Testimony (July 21, 2021), pp. 2-3 (expressing concerns with the opt-model).
[53] *See* PG&E Electric Rule 24; SCE Electric Rule 24; SDG&E Electric Rule 32.
[54] Staff Concept Paper, p. 3.

supply-side DR program, in which case the customer is removed from ELRP," it completely ignores the possibility of competing CCA customer enrollment.[55]

Furthermore, the statement quoted above is problematic as it has been shown that disenrolling customers from DR programs is cumbersome and leads to customer confusion or program disengagement altogether. OhmConnect elaborated at length on this issue in its reply testimony submitted on the PG&E and CEJA residential program proposals that were submitted to the record of this proceeding in supplemental testimony in July 2021.[56] OhmConnect reports that customers "often incorrectly believe that they have successfully disenrolled [from a DR program]—only to find that they have not actually been released from the original IOU DR program."[57] This harm is quantified: "11,000 unique households that have signed up with OhmConnect are unable to fully participate in OhmConnect's DR program because these customers have been unable to disenroll from another DR offering."[58] Customer confusion, and the resulting harm, is certain to be compounded if customers are automatically enrolled into an opt-out program, as recommended in the Staff Concept Paper.[59]

In summary, adopting an auto-enrollment policy for IOU-run DR programs such as ELRP would conflict with Commission policy favoring a "a level playing field to vie for customers to enroll in their demand response programs,"[60] would stifle innovation, and may have a limiting effect on load reduction opportunities. The end-result of auto-enrollment strategies is also likely to result in DR program monopolization with the IOUs and would significantly curtail a CCA's ability to deploy its own DR programs as a critical load management resource.

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[55] Staff Concept Paper, p. 5.
[56] OhmConnect Reply Comments (July 21, 2021), p. 5.
[57] *Id.*
[58] *Id.*
[59] *See* Staff Concept Paper, p. 5.
[60] D.16-09-056, p. 52.

C. Facilitate Data Exchange Between IOUs and CCAs on DR Program Participation

As outlined above, CCAs play an important role in developing demand flexibility programs for their customers, and these programs can support the State in achieving its grid reliability goals. However, to fully achieve this potential, there must be better coordination between CCAs and IOUs on program initiatives in general, and data exchange in particular. MCE encourages the Commission to adopt policies that will facilitate data exchange between IOUs, CCAs and DRPs to allow for faster and more efficient development of new demand flexibility programs.

Specifically, MCE urges the Commission to direct all IOUs to share customer participation data in *all* DR programs, and other pertinent data as relevant. Presently, PG&E's data sharing is limited to the Rule 24 report, which includes only a fraction of customers who are enrolled in the various IOU DR programs, pilots and initiatives. PG&E has been unwilling to share customer participation data on all DR programs citing a lack of direction from the Commission and customer data confidentiality concerns. This results in an incomplete snapshot of program participation data and is hence insufficient to enable MCE (and other CCAs) to know which customers are already enrolled in IOU DR programs. As a result, MCE will likely expend significant time and effort reaching out to customers that are not eligible for MCE's new DR programs as they are already enrolled in IOU DR programs. This is neither a good use of public funds, nor in alignment with the urgency of the request to identify new and additional customer-sited demand reductions.

MCE thus recommends that the Commission direct IOUs and CCAs to share customer participation data on a quarterly basis to allow for streamlined program development, efficient implementation of targeted ME&O campaigns, the prevention of dual enrollment, and to minimize customer confusion.

PG&E's assertion that customer confidentiality impedes such data sharing is misplaced given that CCAs have long-standing non-disclosure agreements ("NDAs") in place with PG&E

since they already exchange customer data on a much broader scale than DR program participation reporting. The Commission should therefore dismiss this alleged impediment and direct all LSEs to share program participation data for *all* DR programs, tariffs and pilots.

MCE appreciates the Commission's recognition of the value that CCAs can have in developing customer programs in the future. In the spring of 2021, the Commission put out a call for action to the CCAs to support the State (and the IOUs) in developing innovative customer programs, tariffs and pilots to reduce demand during net peak hours and increase grid reliability.[61] This call to action was followed up by a workshop to discuss CCA demand flexibility programs, rates and pilot initiatives. If the Commission wants to continue to support CCAs in their endeavors to develop and grow their demand flexibility programs, rates and pilots, it must ensure that the CCAs have the data they need to be successful.

D. Adopt SCT Incentives that are Consistent with the State's Goal of Achieving Load Reduction.

The Staff Concept Paper proposes modifications to SCT programs that also turn a blind eye to the CCA program portfolio. As stated previously, MCE has been administering EE funds under Code Section 381.1(a)-(d) since 2013. Despite MCE's long standing experience running EE programs, the Staff Concept Paper does not mention non-IOU EE program efforts in general, and SCT program efforts in particular. The Commission should ensure that any adopted SCT measures reflect, or complement, existing local measures implemented by MCE and other CCA or Renewable Energy Network ("REN") EE program administrators.

[61] D.21-03-056 at 17-18.

i. MCE disagrees with the Staff Concept Paper proposal to limit SCT installations to "hot climate zones."

MCE disagrees with the Staff Concept Report's implication that installation of SCT technology in "the three coolest regions" that have "*relatively* few 'cooling days' is unlikely to help reduce electric demand during summertime net peaks.[62] From MCE's perspective, actions taken under this ruling should be additive and not reduce the impacts already being realized under the EE portfolio.

In addition to supporting an 'all of the above' approach to SCTs, MCE observes that the climate is changing quickly and even coastal areas that may not traditionally qualify as a "target hot climate zone," are experiencing an increased number of warm temperature days that are driving customers to install air conditioning in historically cooler places.[63] The Commission should take into consideration the changing energy usage in response to hotter temperatures throughout California and not limit the installation of SCT geographically.

ii. MCE does not object to a DR enrollment requirement with any SCT installation so long as the requirement can also be fulfilled through participation in a CCA DR program.

MCE agrees that SCTs should be paired with other demand reduction measures to maximize demand savings. As previously stated, however, the Commission should not adopt any program modification that would unfairly promote IOU DR programs and prejudice CCA or other third-party DR programs. Accordingly, MCE does not oppose a DR-enrollment requirement upon SCT installation so long as the requirement may be satisfied through participation in a CCA, IOU or third-party DR program. MCE further urges the Commission to consider broadening the scope

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[62] Staff Concept Paper, p. 10 (*emphasis added*).
[63] *See* Jung, Yoohyun, "The Bay Area is getting hotter. Is air conditioning becoming standard for homes here?"(June 24, 2021) (Finding that the saturation of AC in the Bay Area has increased over 10% from 2015-2020.]), *accessible at* https://www.sfchronicle.com/local/article/How-many-Bay-Area-homes-have-air-conditioning-16273057.php.

of this integration requirement to include other smart technology measures such as EV charging, energy storage devices, or heat pumps.

iii. MCE agrees that EE Program Administrators should be allowed to maintain existing SCT budgets, including local SCT programs.

For the reasons explained above, SCTs remain an important tool for leveraging customer involvement and maximizing DR savings. This is particularly so where SCTs are offered as part of a larger and more comprehensive DR or EE project. MCE continues to provide smart thermostats or other smart devices in its EE programs. Two of these programs in particular are aimed at hard-to-reach customer segments (*i.e.*, low-income multi-family and moderate-income single-family customers). These programs provide smart thermostats along with other efficiency measures such as attic insulation or duct sealing and combine the upgrades with tenant or homeowner education that further amplifies the performance of the smart thermostats. These programs work through local channels to recruit customers. Smart thermostats offer an attractive entry point that can help convince a customer to undertake a more comprehensive project. To pull smart thermostats out of these comprehensive, locally tailored EE programs and into a statewide program would reduce the efficiency gains associated with the smart thermostats by removing the complementary upgrade and reduce customer engagement in local programs by removing a driver of participation.

Accordingly, MCE agrees that, at a minimum, program administrators should be permitted to retain existing SCT budgets and that local SCT programs must continue to be an important part of EE portfolios.

II. CONCLUSION

MCE appreciates the Commission's consideration of the above-discussed modifications to the Staff Concept Paper.

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CHAPTER FOUR

CONCLUSION

I. CONCLUSION

As explained above, MCE has already dedicated significant time—and funding—to developing innovative demand flexibility programs that could be leveraged to quickly meet the grid reliability and load reduction goals announced in the Emergency Proclamation and pursued in this Rulemaking. These programs present the Commission with an opportunity to capture a low-hanging fruit opportunity for demand reduction beginning in 2022, by directing ratepayer funding to scale the programs and maximize load reduction impact. Specifically, MCE respectfully recommends that the Commission authorize the below funding proposals:

1. $11,560,000 to expand upon the success of its *Peak FLEXmarket* program;
2. $4,408,000 to leverage MCE's *Energy Storage Program*; and
3. $1,776,000 to leverage MCE's EV charging program, *MCEv Sync*.

Additionally, in consideration of the Staff Concept Paper, MCE strongly encourages the Commission to hold space for CCA DR programs, which show significant expansion capabilities. At an absolute minimum, the Commission should ensure that its policies and mandates are designed to allow CCAs, DRPs, and IOUs continue to compete on a level playing field to drive market innovation and maximum load management impacts. To this end, MCE recommends that the Commission consider the following improvements and modifications to existing policy:

1. Allow for market-driven development of DR and other demand flexibility programming;
2. Avoid an auto-enrollment program model for DR programs;
3. Require data-sharing between CCAs and IOUs regarding DR program participation; and

4. Continue to use SCT as an important load reduction and customer-engagement tool.

MCE thanks the Commission for its consideration of this Opening Testimony.

APPENDIX A

STATEMENT OF QUALIFICATIONS FOR ALICE HAVENAR-DAUGHTON

Appendix A: Statement of Qualifications for Alice Havenar-Daughton

Q1: Ms. Havenar-Daughton, please state your name, position, and address.

A1: My name is Alice Havenar-Daughton. I am the Director of Customer Programs at MCE. My business address is 1125 Tamalpais Avenue, San Rafael, California 94901.

Q2: Please describe your background.

A2: In this role, I oversee the design, implementation, and evaluation of demand flexibility programs that help customers reduce energy usage and shift loads away from peak demand hours. I have been working with customer programs since I began at MCE in July of 2014. Prior to this, I worked at Opinion Dynamics Corporation as a Senior Analyst. I served as the lead analyst, where I performed process and impact evaluations of EE and DR programs in California and across the country. I have also worked for the Alliance for Climate Protection as a Fellow, where I focused on analyzing national climate and energy legislation to support renewable energy advocacy efforts.

Q3: What is the purpose of your testimony?

A3: As the Director of MCE's Customer Programs, I am providing information on customer programs and policies that will promote demand flexibility and achieve critical load reductions in the coming years.

Q4: Do you adopt your prepared direct testimony (dated September 1, 2021) as your sworn testimony in R.20-11-003 (Extreme Weather)?

Q4: Yes.

Q5: Does this conclude your statement of qualifications?

A5: Yes, it does.

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE CALIFORNIA ENERGY COMMISSION ON THE DRAFT CEC PRELIMINARY 2022 SUMMER SUPPLY STACK ANALYSIS
August 11, 2021

Docket Number 21-ESR-01
Energy System Reliability

I. INTRODUCTION

The California Community Choice Association (CalCCA)[1] submits these comments to the California Energy Commission (Commission) in Docket 21-ESR-01, on the *Draft CEC Preliminary 2022 Summer Supply Stack Analysis*, dated August 11, 2021 (Stack Analysis). CalCCA appreciates the efforts taken by the Commission to perform this analysis and the opportunity to comment on the assumptions and results.

II. COMMENTS

Recommendation 1: The Commission should favor loss-of-load (LOLE) study results when evaluating the reliability shortfall estimated to occur in summer 2022 and when informing future procurement decisions.

Stack analyses, by their nature, provide only a single point estimate of capacity sufficiency. They thus fail to account for uncertainty about supply, demand, weather, renewable generation, and the complexities of storage dispatch. While stack analyses are a useful data point

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

in identifying the existence of possible reliability issues (i.e. they show that the system may be underbuilt relative to the load under certain assumptions), they are not on their own sufficient for calculating the size of a procurement need, because the result is highly dependent on the input assumptions made.

CalCCA notes that the stack analysis has an enormous range of possible quantities of procurement needed, from 600 MW to 5,200 MW.[2] These figures represent approximately 1 to 11 percent of CAISO peak load in 2020.[3] This large range highlights the limits of stack analyses—it is not clear how to translate this range into a procurement requirement, nor is it clear the level of reliability risk achieved by procuring somewhere within this range. Ratepayers will ultimately bear the cost of this procurement, and they deserve a careful and measured consideration of actual system need rather than broad-brush estimates from a single stack analysis.

In contrast to stack analyses, loss-of-load expectation (LOLE) models capture the complexities of actual system operation, including economic dispatch, must-run generation, and economic imports (which are not included in the Stack Analysis). LOLE models are also capable of modeling many different scenarios, giving a much better picture of actual risk and thus providing more accurate metrics about the probability of a resource shortfall in any given hour, which is crucial information for decision-making.

The CEC issued a *Midterm Reliability Analysis & Incremental Efficiency Improvements to Natural Gas Power Plants* LOLE analysis that examined years 2022-2026 on August 30,

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2 CEC Stack Analysis at 4. https://efiling.energy.ca.gov/GetDocument.aspx?tn=239251&DocumentContentId=72701

3 California ISO Peak Load History 1998 through 2020. Peak load in 2020 was 47,121 MW. Available at: https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

2021.[4] The Commission should favor the results of the LOLE analysis when evaluating the reliability shortfall estimated to occur in summer 2022, and when informing future procurement decisions, for the reasons outlined above.

Recommendation 2: The Commission should publish more detailed information about the generating resources used in its analysis, and clarify some of the assumptions made.

Table 2 and Figures 1-3 of the Stack Analysis summarize the set of supply-side resources used in the analysis[5], but they do not provide detailed information that would allow stakeholders to meaningfully evaluate whether this set of resources is appropriate. CalCCA has the following specific requests so that it can assess the appropriateness of these data.

First, the Commission should provide more information about the resources assumed in this analysis. The analysis references "CPUC Procurement of 840 MW by August 2022" and "CPUC Expedited Procurement carry over of 556 MW from 2021," but it is not clear what those resources are, and exactly what CPUC proceedings are being referred to. To the extent this information is confidential, the Commission can aggregate up to resource types to mask it, but getting a more granular picture of the resource mix would help parties to better evaluate the analysis.

Second, the Commission should validate its resource stack versus the 2022 Preliminary CAISO NQC list[6]. In theory, all or nearly all the resources used in this analysis should be on this list.

4 https://efiling.energy.ca.gov/GetDocument.aspx?tn=239554&DocumentContentId=72991
5 CEC Stack Analysis at 3-7.
6 http://www.caiso.com/Documents/Draft-Final-Net-Qualifying-Capacity-Report-for-Compliance-Year-2022.xls

Third, the Commission should clarify why an additional 1,500 MW of hydro derates[7] are being applied on top of the hydro's Net Qualifying Capacity (NQC) value. NQC should already capture drought conditions, because it is derived using a rolling average of actual historical hydro generation data, some of which will contain drought years. Although CalCCA understands that the Commission wishes to model a system that is much dryer than this rolling average, it should describe why 1,500 MW is an appropriate number to be applied on top of the NQC amount.

Fourth, the Commission should quantify the amount of demand response assumed, and explain why it is appropriate.

Fifth, the Commission should publish the charts in tabular form to allow stakeholders to review.

Sixth, for consistency with the rest of the analysis (which assumes that droughts reduce pumping load and hydro capacity), the Commission should revisit its assumptions on imports. The analysis currently uses an average of resource adequacy (RA) import showings from 2015-2020, and appears to use a single imports value in Figures 1-3, regardless of the month.[8] This single value does not account for variation in imports across months[9], does not count economic imports (which are likely to be greater than zero), and ignores the fact that there is likely less import capacity available in drought months. Figure 1, shown below, shows historic California

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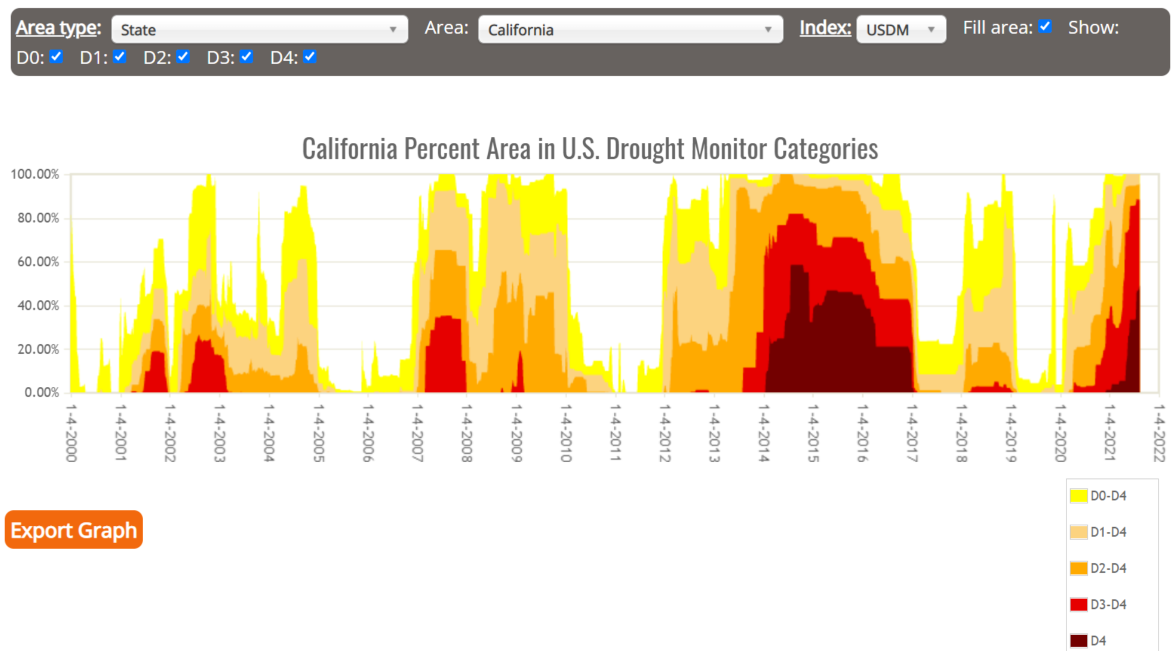
7 CEC Stack analysis at 3.

8 CEC Stack analysis at 5-7.

9 Across-month variation is substantial—according the CPUC's 2019 RA report, in July, August, and September, import RA was 4,901 MW, 3,968 MW, and 4,737 MW respectively. This is a difference of 933 MW between the largest and smallest value. CPUC 2019 Resource Adequacy Report at 15, Table 4. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf

drought data from the US Drought Monitor, with darker colors indicating more severe drought.[10] 2014-2016 are abnormally dry years, with more exceptional droughts, and are thus the most appropriate for evaluating available imports under drought conditions. Using an average from 2015-2020 likely overstates import availability, as it captures both dry and wet years.

Figure 1: Drought Data in California



Therefore, CalCCA recommends using specific monthly values based on RA Import data from July-Sep in the dry years of 2014-2016, and counting economic imports as well.

Seventh and finally, the Commission should confirm whether its analysis includes or does not include publicly-owned utility (POU) loads and resources in the CAISO footprint. POU load represents approximately 9 percent of load in the CAISO footprint,[11] and it is important that

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10 Data is from https://droughtmonitor.unl.edu/DmData/TimeSeries.aspx for California. The color scale in the legend consists of the following categories: D0 (Abnormally Dry), D1 (Moderate Drought), D2 (Severe Drought), D3 (Extreme Drought), and D4 (Exceptional Drought).

11 https://www.cmua.org/2021-issue-brief-electric-relaibility "Collectively, POUs serve about 9 percent of the electric load in the CAISO system."

any procurement order that is applied to CPUC-jurisdictional LSEs (i.e. not POUs) take this into account.

Recommendation 3: The Commission should clearly identify what would count as incremental to the new procurement requirement.

From the Stack Analysis, it is not clear what types of resources could be used to fulfill the purported gap between supply and demand. Additionally, it is unclear whether the gap can be filled by existing resources, new build, or both—it is unlikely, for example, that 5 GW of new resources can be brought online before next summer. In other words, it is not clear if the problem is a shortage of RA contracts on existing resources, a shortage of new build, or both.

Therefore, the Commission should clarify which of the following categories of resources below would be eligible for filling this gap. To the extent these resources have identifiers such as a CAISO ID or a project name in the CAISO Interconnection Queue[12], the Commission should provide those.

- Additional RA Contracting of existing in-state generation
- Additional RA imports contracting
- Repowering thermal generation
- Extending retirement dates
- New build
- New Storage
- Demand response

[12] http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx

III. CONCLUSION

CalCCA appreciates Commission staff's efforts in performing its Preliminary Summer 2022 Stack Analysis and looks forward to further collaboration on this topic.

Dated: September 7, 2021

(*Original signed by*)

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Comments of California Community Choice Association
On the CAISO EIM Resource Sufficiency Evaluation Enhancements
Initiative Straw Proposal and Workshop Presentations/Discussion

1. **Please provide a summary of your organization's comments on the straw proposal:**

   California Community Choice Association (CalCCA) appreciates the opportunity to submit comments on the Energy Imbalance Market (EIM) Resource Sufficiency Evaluation (RSE) Enhancements Straw Proposal,[1] and the August 23, 2021 Workshop Presentations/Discussion. CalCCA generally agrees with the California Independent System Operator Corporation's (CAISO) principles outlined in the Straw Proposal, and believes that the proposed enhancements will improve the accuracy and equitable application of the RSE. These comments are limited to CalCCA's support of the CAISO's decision to delay consideration of RSE failure consequences to after the implementation of the enhancements. CalCCA opposes the imposition of any financial consequences or operational consequences beyond the current capping of incremental upward EIM transfers.

2. **Please provide a summary of your organization's comments on the section of the proposal related to the capacity test modifications - intertemporal constraints, specifically the use of the short-term unit commitment horizon:**

   No comments at this time.

3. **Please provide a summary of your organization's comments on the section of the proposal related to the flexible ramping test modifications:**

   No comments at this time.

4. **Please provide a summary of your organization's comments on the section of the proposal related to the balancing test modifications, including the potential for changes in revenue allocation:**

   No comments at this time.

5. **Please provide a summary of your organization's comments on the proposed ability for an EIM entity to represent demand response via adjustments to the forecasted demand requirement. Please provide feedback on if the existing penalty structure for under-delivery is sufficient to prevent misuse of this functionality:**

   No comments at this time.

6. **Please provide a summary of your organization's comments on the proposed qualifications for import schedules the CAISO is able to use as an input to the RSE:**

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[1] *EIM Resource Sufficiency Evaluation Enhancements Straw Proposal,* Aug. 16, 2021 (Straw Proposal).

No comments at this time.

7. **Please provide a summary of your organization's comments on the proposal to limit incremental EIM transfers when firm load is used as non-spin/spin reserves:**

   No comments at this time.

8. **Please provide a summary of your organization's comments on the section of the proposal related to additional transparency and data availability:**

   No comments at this time.

9. **Please provide a summary of your organization's comments on the additional metrics that the Department of Market Monitoring can develop for the RSE:**

   No comments at this time.

10. **Please provide a summary of your organization's comments on the section of the proposal relating to the uncertainty calculation; specifically the use of the last 3 months of deviation data as well as the 95% confidence interval:**

    No comments at this time.

11. **Please provide your organization's comments on the proposal to address the RSE failure consequences in the phase 2 of this initiative, including desired timelines for the start on phase 2 of the initiative.**

    CalCCA appreciates the CAISO concluding that imposing revised RSE failure consequences at this time is not appropriate given the enhancements being made with this initiative as well as the pricing improvements made in the *Market Enhancements for Summer 2021 Initiative.* CalCCA also agrees with the CAISO that any changes to the current RSE failure consequences should not be considered until the enhancements in Phase 1 are implemented and data regarding any RSE failures at that time are evaluated. However, during any phase of this initiative, CalCCA opposes any future development of additional consequences (beyond the current capping of incremental upward EIM transfers) for failure of the RSE, including financial penalties or additional operational consequences.

    As noted by the CAISO in the Straw Proposal, "[t]he addition of financial consequences for a failure of the EIM's RSE represents a fundamental change to the existing voluntary nature of EIM Participation."[2] EIM entities can voluntarily elect to participate in and make supply available to the EIM through the base scheduling process. EIM participants already face existing penalties for non-compliance with responsibilities in the Balancing Area Authority. In addition, the CAISO's market process clears supply with forecasted demand. To do this resource adequacy resources have a must offer obligation to ensure sufficient offers are made

[2] Straw Proposal at 21.

available to the market to meet forecasted demand. Any financial consequences for failure of the RSE could dissuade entities from fully participating in the EIM to avoid the risk of incurring financial penalties. In addition, even if financial penalties are limited to times of stressed grid conditions (as contemplated in the Issue Paper[3]), entities could be dissuaded from participating at a time when transfers are most beneficial.

Operational consequences beyond the current capping of incremental upward EIM transfers to prevent leaning should not be considered. Any such operational consequences could exacerbate reliability challenges if a decrease in the transfer limit occurs when an entity is already experiencing reliability challenges.

CalCCA does not support financial or additional operational consequences for failing the RSE, as such consequences will have adverse impacts on the EIM, a voluntary market, by hindering EIM participation beyond what is necessary to avoid leaning.

12. Please provide your organization's comments on the proposal to address the load forecast adjustments topic in phase 2 of this initiative:

No comments at this time.

13. Please provide your organization's comments on the proposed EIM Governing Body classification to have primary authority to approve the EIM RSE final proposal:

No comments at this time.

14. Please provide any additional comments on the EIM RSE Enhancements initiative that have not previously been addressed:

No comments at this time.

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3 *EIM Resource Sufficiency Evaluation Enhancements Issue Paper*, May 28, 2021 (Issue Paper) at 4.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues.	Rulemaking 13-11-005 (Filed November 14, 2013)

REPLY COMMENTS OF MARIN CLEAN ENERGY ON THE AUGUST 6 EMAIL RULING TO ADDRESS THE GOVERNOR'S EMERGENCY PROCLAMATION OF JULY 30, 2021

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September 10, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues.	Rulemaking 13-11-005 (Filed November 14, 2013)

REPLY COMMENTS OF MARIN CLEAN ENERGY ON THE AUGUST 6 EMAIL RULING TO ADDRESS THE GOVERNOR'S EMERGENCY PROCLAMATION OF JULY 30, 2021

In accordance with Rule 6.2 of the Rules of Practice and Procedure ("Rules") of the California Public Utilities Commission ("Commission") and the schedule set forth in the August 6, 2021 *Email Ruling Requesting Comments/Proposals to Address Governor's Proclamation of July 30, 2021* ("August 6 Ruling"), Marin Clean Energy ("MCE")[1] submits the below Reply Comments in response to issues raised in certain parties' Opening Comments in the above-captioned proceeding.

I. INTRODUCTION

Overall, MCE appreciates and supports the proposals raised by a majority of stakeholders to eliminate market barriers and quickly deliver load reduction impacts by June 1, 2022. In fact, MCE is already running a program—the *Peak FLEXmarket*—that implements several of the measures identified by parties in opening comments as key to achieving load reduction and improved grid reliability. It is therefore clear that directing ratepayer funds to scale the *Peak*

[1] MCE, California's first CCA, is a not-for-profit public agency that began service in 2010 with the goals of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs. MCE is a load-serving entity ("LSE") serving approximately 1,200 MW peak load, providing electricity generation services to more than 1.1 million people in 36 communities across Marin, Contra Costa, Napa and Solano counties.

FLEXmarket is not only a unique opportunity to quickly achieve the goals of the Emergency Proclamation, but also presents a prudent use of ratepayer funds, which can lay the groundwork for further market development.

II. COMMENTS

A. Several Parties Make Conceptual Recommendations that Support the *Peak FLEXmarket*

Several parties identify programmatic changes or market goals that are in fact already underway in MCE's *Peak FLEXmarket* program. These proposals exemplify why it is such a unique opportunity for the Commission to leverage MCE's *Peak FLEXmarket* program to support the Governor's and the Commission's goals of delivering peak load reduction by June 1, 2022.

For example, the California Efficiency + Demand Management Council (the "Council") urges the Commission to remove the winner-take-all model whereby energy efficiency ("EE") contracts are awarded to a single firm even though "a large number of organizations [in California] develop energy projects that could reduce grid constraints."[2] The Council urges the Commission to "direct program administrators to establish a market-access model that enables any organization to enroll projects that support both customers and the grid."[3] Such a "market-access model" is already deployed through MCE's *Peak FLEXmarket*,[4] which was designed to close this market gap and to allow a multitude of demand flexibility approaches to work collectively and collaboratively towards enhanced grid benefits, without leaving anything on the table.

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[2] *Opening Comments of the California Efficiency + Demand Management Council on Administrative Law Judge's Ruling Requesting Energy Efficiency Comments/Proposals to Address Governor's Proclamation of July 30, 2021* (August 31, 2021) (hereafter, "The Council Opening Comments"), p. 8.
[3] *Id.* at 9.
[4] *See Opening Comments of Marin Clean Energy to Address Governor Newsom's July 30, 2021 Proclamation* (August 31, 2021) (hereafter, "MCE Opening Comments"), pp. 12, 16 (discussing the wide reach of the *Peak FLEXmarket* and number of projects enrolled).

Additionally, the Council urges the Commission "to use the Avoided Cost Calculator ("ACC") to quantify the value of individual resources and [to] set the market price for that resource based on that same value."[5] The Council reasons that "[e]stablishing resource value in this way would provide critical transparency to the market while motivating and rewarding the resources with high grid value."[6] MCE agrees, and designed the *Peak FLEXmarket* towards this end. The *Peak FLEXmarket* includes a transparent price signal that bases the daily load shift incentive on the avoided costs as determined by the ACC and Resiliency Event payments on California Independent System Operator ("CAISO") day-ahead market prices, creating a consistent price signal across resources.[7]

The Natural Resources Defense Council ("NRDC") also recommends implementing programs that are in line with those already underway in MCE's *Peak FLEXmarket*,[8] and NRDC even cites "MCE's FLEXmarket" as an example of the type of program it recommends.[9] Indeed, NRDC specifically recommends "expediting the approval of *integrated [EE] and [DR] programs*" to target "high net-peak load" reduction through performance incentives, which precisely describes the *Peak FLEXmarket*.[10] Furthermore, NRDC proposes certain measurement and verification ("M&V") strategies to ensure load reduction, such as the inclusion of a control group or a normalized energy consumption ("NMEC") billing analysis approach for customer segments

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[5] The Council Opening Comments, p. 9.
[6] The Council Opening Comments, p. 9.
[7] *See* MCE Opening Comments, pp. 6-8.
[8] NRDC states that program administrators should develop initiatives that: (1) target customers with high reliability savings potential; (2) incentivize target customers to install efficient equipment and demand management controls; and (3) enroll these customers in active load management programs which compensate customers for the reliability services they provide based on measured performance. (NRDC Opening Comments, p. 4.). MCE's *Peak FLEXmarket* is designed to achieve each of these three goals.
[9] NRDC Opening Comments, p. 5 (describing MCE's Flex Market as an example of a "targeted and specific application of broader market-based pay-for-performance programs.")
[10] NRDC Opening Comments, p. 8 (emphasis added).

where a control group cannot be developed.[11] MCE agrees that such M&V is critical, and MCE's *Peak FLEXmarket* program utilizes both NMEC and comparison group adjustments in determining impacts.[12]

In addition to MCE's support for NRDC's proposals (many of which MCE has already implemented in its program), MCE would like to offer the following consideration on one proposal that NRDC includes in its hypothetical program design.[13] NRDC proposes to "[e]ither develop a list of incremental EE and DR measures," such as high efficiency cooling systems, smart thermostats, refrigeration upgrades and controls, *etc.*, or, in the alternative, to offer a pay for performance program.[14] MCE strongly encourages the Commission to adopt the latter approach, since the prescriptive approach of offering specific measures is unnecessarily limiting, does not guarantee performance, and overlooks behavioral and manual demand reduction opportunities.

Overall, MCE was delighted to read about parties' widespread support of the concepts that the *Peak FLEXmarket* builds upon. MCE is in a unique position to grow this program and quickly deliver the near-term load impacts demanded by the Emergency Proclamation.[15] Further, MCE is willing to submit to periodic evaluations that the Commission (or stakeholders) may propose and develop "lessons-learned" of the *Peak FLEXmarket* to ensure that the program continues to deliver the desired load impact benefits and that it can serve as an exemplary program for other entities to develop.

[11] NRDC Opening Comments, p. 6.
[12] *See* MCE Opening Comments, pp. 6, 11.
[13] *See* NRDC Opening Comments, p. 4.
[14] NRDC Opening Comments, p. 5.
[15] *See* MCE Opening Comments, pp. 7, 10 (discussing MCE's ability to work quickly and to attract program interest).

B. MCE's *Peak FLEXmarket* Presents a First-of-Its-Kind Application of Recurve's Demand FLEXmarket Platform that Can Be Quickly Scaled

MCE appreciates and fully supports Recurve's program proposals made in Opening Comments[16] and would like to offer a few clarifications on similarities and differences between Recurve's and MCE's program proposals. As explained in MCE's opening comments, Recurve developed the Demand FLEXmarket platform (*i.e.*, the tools and technology) on which MCE's Commercial Energy Efficiency Market and *Peak FLEXmarket* run.[17] MCE is the first entity to leverage Recurve's innovative platform, with these two programs already in operation, and thus MCE is uniquely positioned to scale its reach.

The Commercial Energy Efficiency Market is already positioned as a significant contributor to MCE's EE portfolio impacts, and the *Peak FLEXmarket* has been developed from the ground up to MCE's specifications.[18] While MCE fully supports Recurve's proposal to bring the same program concept to other CCAs,[19] MCE notes two critical reasons for why the Commission should approve funding for MCE's *Peak FLEXmarket* proposal now,[20] and then, on a separate track (and an unavoidably longer timeline), the Commission should create a pathway for CCAs to quickly deploy similar programs.

First, MCE's *Peak FLEXmarket* is already operational, with nearly 1,500 meters already tracked under 5 aggregator portfolios, and more are expected by the close of this summer's peak

[16] *Comments of Recurve Analytics, Inc. on Email Ruling Requesting Comments / Proposals on Energy Efficiency to Address Governor's Proclamation of July 30, 2021* (August 31, 2021) (hereafter, "Recurve Opening Comments").
[17] *See* MCE Opening Comments, pp. 3-4.
[18] *See id.* at 4-5.
[19] *See* Recurve Opening Comments, p. 12.
[20] As MCE explains in its Opening Comments, new program development is likely to take 12 months to design, develop, launch, and enroll customers, and thus would not deliver benefits by June 1, 2022, as directed in the Emergency Proclamation. (MCE Opening Comments, pp. 16-17.)

season.[21] The *Peak FLEXmarket* also benefits from running in parallel to MCE's existing EE programs. Developing new Demand FLEXmarket programs at other CCAs is a great proposal but will inevitably require time—even on a "fast-track pathway"[22]— as individual CCAs work through their own program processes and requirements.

Second, MCE has already identified a funding and cost recovery mechanism for scaling the *Peak FLEXmarket* in 2022 and 2023.[23] As MCE explains in opening comments, MCE has approximately $11.9 million available for use in "unrequested funds" under the current EE portfolio.[24] The Commission can readily direct MCE to use these ratepayer funds, which were already allocated to MCE, for the *Peak FLEXmarket* program.

With this in mind—and particularly in light of the timeline espoused in the Emergency Proclamation—MCE urges the Commission to authorize MCE's *Peak FLEXmarket* funding request as soon as possible, through a decision on the August 6 Ruling. In parallel, MCE encourages the Commission to create an avenue for other CCAs to receive ratepayer funding to develop and run similar programs from the Demand FLEXmarket platform as proposed in Recurve's opening comments.

C. MCE Agrees that that the Commission's Cost Effectiveness Parameters Require Modification.

In Opening Comments, MCE proposed modifying the Commission's cost effectiveness ("CE") requirements for performance-based, meter-based EE programs that pay on Total System Benefits ("TSB"), and expediting the update of the Cost Effectiveness Tool ("CET") to allow for

[21] *See* MCE Opening Comments, p. 5.
[22] Recurve Opening Comments, p. 12.
[23] *See* MCE Opening Comments, pp. 14-15 (recommending use of MCE's remaining "unrequested funds" to expand the Peak FLEXmarket program consistent with the objectives of the Emergency Proclamation).
[24] *Id.*

custom load shapes for reporting savings claims.[25] A majority of commenting parties appear to agree that some degree of CE modification is necessary to achieve optimal load management and to do so on the timeline expected by the Emergency Proclamation.[26]

MCE particularly supports the Council's argument that structural cost effectiveness reform is in order.[27] To this end, MCE would like to clarify and elaborate on its opening comments[28] that we continue to recommend moving from the total resource cost ("TRC") to the program administrator cost ("PAC") test for all EE programs as soon as possible.[29] In the interim, however, MCE recommends that the Commission take immediate steps to modify CE requirements for pay-for-performance programs— particularly market-driven programs that do not directly pay customer incentives— as proposed in MCE's opening comments.[30] This near-term step offers a low-risk modification to CE that can be quickly implemented to produce meaningful grid impacts in 2022 and 2023.[31]

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[25] MCE Opening Comments, pp. 17-19.

[26] *See, e.g.*, *Opening Comments of Gridium Inc. on Administrative Law Judge's Ruling Requesting Energy Efficiency Comments/Proposals to Address Governor's Proclamation of July 30, 2021*, (August 31, 2021) pp. 2-3 (recommending a shift from TRC to PAC as the primary CE test); *Comments of East Bay Community Energy and California Choice Energy Authority on the Email Ruling* (August 31, 2021), pp. 2-3 (identifying CE reform as a "low-hanging fruit" measure that can accelerate the deployment of EE resources to reduce peak load by summer 2022); The Council Opening Comments, p. 3 (recommending adoption of the PAC test because it "more accurately addresses the resource needs given the grid and climate conditions we are facing today" and because the PAC test "places EE on par with other behind-the-meter DERs as well as supply-side resources."); Recurve Opening Comments, p. 9 (advocating use of the PAC test as "a more accurate reflection of how administrators could directly buy resources from the market.")

[27] The Council Opening Comments, p. 3.

[28] *See* MCE Opening Comments, p. 18.

[29] MCE made the same argument in Opening Comments on the Proposed Decision Regarding Assessment of Energy Efficiency Potential and Goals and Modification of Portfolio Approval and Oversight Process, submitted on May 6, 2021 (p.5f)

[30] *See* MCE Opening Comments, p. 18.

[31] MCE Opening Comments, pp. 18-19.

D. MCE Supports Party Proposals to Bring the ACC Into Alignment with the True Value of Load Reduction During Peak Hours.

MCE supports proposals, made by several parties, to bring the ACC into alignment with the true value of load reduction during peak hours. NRDC, among others, advocates for the development of a reliability-adder to account for avoided costs for measures and programs that target reliability hours.[32] NRDC notes that the ACC does not capture the full cost of reliability:

> There are grid benefits of managing load during capacity constrained emergency hours that may not be completely captured by avoided costs. Wholesale electricity prices are very high during these hours, and load-serving entities ("LSEs") are sometimes forced to meet their reliability needs through expensive and polluting resources such as diesel and portable gas generators. CAISO calls for load shedding which also comes at an opportunity cost.[33]

MCE agrees. MCE supports the concept of creating a mechanism, such as a reliability-adder, to better reflect and incorporate reliability costs in the ACC.

Taking it one step further, MCE notes that, in aggregate, these comments demonstrate the cost-effectiveness of EE measures and the significant role that EE can play in reducing peak demand. For the hourly avoided cost to truly spur EE projects that contribute to peak demand reduction, program administrators need to be able to claim those savings in the hours they occur, rather than using predetermined "load shapes" based on the average performance of deemed measures.

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[32] NRDC Opening Comments, p. 3; *see also Enovity Opening Comments on Administrative Law Judge's Ruling Requesting Energy Efficiency Comments/Proposals to Address Governors' Proclamation of July 30, 2021* (August 31, 2021), p. 2 ("Including a resiliency benefit in the [ACC] will (more) fully recognize the temporal value of energy savings, realizing the cost-effectiveness of projects that serve the Governor's order in the near term."); *Pacific Gas & Electric Company's (U-39 M) Comments to the Administrative Law Judge's Email Ruling Requesting Comments/Proposals to Address Governor's Proclamation of July 30, 2021*, (August 31, 2021) pp. 11-12 (discussing the need to "fully account for the reliability benefits that [EE] can offer" when calculating avoided costs).
[33] NRDC Opening Comments, p. 3.

For example, in MCE's *Peak FLEXmarket*, a participating aggregator is incentivized to find customers that have high usage during the 4-9pm window and to propose projects to reduce that peak demand. When MCE compensates the aggregator for that project, those savings will generate a higher incentive because MCE measures the savings at the meter and pays based on measured, hourly savings. However, when MCE submits the claim for that project to the CPUC to determine the contribution to TSB goals, an average savings load shape is applied that can erase the added benefit associated with targeting a customer with high peak hour usage. This creates a disincentive to optimize savings to reduce peak demand. To properly align incentives, the CPUC should build in the capability for Program Administrators to claim project savings using hourly measured impacts from the meter instead of average deemed load shapes.

E. The Commission Should Authorize Funding and Implementation for any Approved Program Proposals Through a Decision on the August 6 Ruling.

To achieve load reduction impacts on the timeline sought in the Emergency Proclamation, the Commission must direct any funding authorization and implementation for new program proposals through a Decision on the August 6 Ruling.

While MCE in principle supports NRDC's recommendation that program administrators ("PAs") request any additional funding needs through the Annual Budget Advice Letters ("ABAL") or a Tier 2 Advice Letter,[34] this recommendation is impractical and infeasible in this instance, considering the urgency of the Emergency Proclamation and the realities of PA budgeting. It is not possible for PAs to include program proposals made in response to the August 6 Ruling in the ABAL for program years ("PYs") 2022 and 2023 anymore. The upcoming ABAL

[34] *See* NRDC, p. 4 ("To the extent possible PAs should apply existing program budget caps to prioritize these initiatives; if PAs need additional budgets for funding targeted energy programs, they should request those additional funds with a showing of need through their Annual Budget Advice Letters (ABAL) if feasible. PAs also should have the option of Tier 2 advice letters for any additional budget approval.")

is due on November 1, 2021, or 30 days after a final decision on the 2021 Potential and Goals ("P&G") study, whichever is later.[35] As such, any portfolio planning for PYs 2022 and 2023 is already complete and any revision to accommodate new program proposals would require PAs to revisit the budgets and program design for *all EE programs* for 2022 and 2023. It simply is not possible to revamp the entire portfolio planning process in time for the November 1 ABAL filing once the Commission issues a decision on the August 6 ruling.

Even filing a separate and additional advice letter ("AL") to request the funds for the programs proposals made in response to the August 6 ruling would be impractical or even infeasible under the timeline espoused in the Emergency Proclamation. ALs generally require at least 3-6 months to resolve, longer if they are protested, which is then followed by program design and rollout. The Commission simply does not have enough time to undergo this (usually appropriate) process given the urgency of the Emergency Proclamation and the need to have projects *delivering grid benefits* by summer 2022.

Accordingly, MCE recommends that funding and implementation authorization for specific program proposals that include all the details outlined in the Proposal Guidance provided in the August 6 Ruling should be made in a Commission decision on the August 6 Email Ruling. Furthermore, MCE continues to recommend that Implementation Plans should be filed within sixty days of Commission approval, per the requirements of Decision 18-05-041, which will allow for further stakeholder and Commission review.[36]

[35] *See Proposed Decision Adopting Energy Efficiency Goals for 2022-2032*, (mailed August 20, 2021), p. 21, which proposed decision is scheduled to be voted on during the Commission's September 23, 2021 Business Meeting.
[36] *See* MCE Opening Comments, pp. 17-18; *see also* Opening Comments of SoCal REN at 4.

III. CONCLUSION

In sum, and consistent with MCE's opening comments, MCE recommends that the Commission take the following actions to rapidly achieve the grid reliability goals identified by the Emergency Proclamation and the August 6 Ruling:

i. Authorize MCE's request for $11.5M in funding for the *Peak FLEXmarket* from MCE's unrequested EE funds under the current EE portfolio cycle;
ii. Modify existing CE requirements for pay-for-performance programs to either exclude customer costs or move to the PAC;
iii. Initiate broader CE reform as a longer-term goal;
iv. Expedite the Commission's update of the CET tool to allow for custom-load shapes for reporting savings claims.

MCE thanks Commissioner Shiroma, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of these comments and proposals.

Respectfully submitted,

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September 10, 2021

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Address Energy Utility Customer Bill Debt Accumulated During the COVID-19 Pandemic.	R.21-02-014 (February 11, 2021)

NOT CONSOLIDATED

Order Instituting Rulemaking Evaluating the Commission's 2010 Water Action Plan Objective of Achieving Consistency between Class A Water Utilities' Low-Income Rate Assistance Programs, Providing Rate Assistance to All Low – Income Customers of Investor-Owned Water Utilities, and Affordability.	R.17-06-024 (June 29, 2017)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON RULING SETTING JOINT STATUS CONFERENCE AND ORDERING COMMENTS

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September 13, 2021

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SUMMARY OF RECOMMENDATIONS

- Remove the Section 3/Issue 7 questions from the scope of this proceeding as they relate to the CAPP program by granting CalCCA's Motion to Modify Scope to Conform to Government Code §16429.5 in order to prevent the delay of the CAPP funding for CCA customers in need;
- In the absence of a ruling on, or a denial of, CalCCA's Motion, grant the requests in CalCCA's Brief on Scoped Issue 7, Allocation of Payments on Arrearages for CCA Customers, to complete the Commission's consideration of Section 3/Issue 7 by September 30, 2021 and find that the CAPP allocation and pro rata allocation of partial payments on past due accounts between IOUs and CCAs are in accordance with Government Code sections 16429.5(f) and (g)(4);
- Refrain from implementing any further COVID-19 arrearage relief programs until the CAPP funding is allocated and the magnitude of remaining arrearages is ascertained; and
- Examine the process of customer data exchanges between CSD and the IOUs after the CAPP Applications are submitted.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Address Energy Utility Customer Bill Debt Accumulated During the COVID-19 Pandemic.	R.21-02-014 (February 11, 2021)
NOT CONSOLIDATED	
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON RULING SETTING JOINT STATUS CONFERENCE AND ORDERING COMMENTS

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Ruling Setting Joint Status Conference and Ordering Comments* (Ruling), issued July 29, 2021, and *E-Mail Ruling Correcting Schedule and Due Dates of Comments in Administrative Law Judge Rulings Dated July 29, 2021* (E-Mail Ruling), issued August 3, 2021.

[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

I. INTRODUCTION

CalCCA appreciates the opportunity to submit these comments responsive to the questions posed in the Ruling regarding the need for electric utility and community choice aggregator (CCA) customer arrearage relief as a consequence of the COVID-19 pandemic. CalCCA's members are CCAs providing electric generation service to unbundled customers of the investor-owned utilities (IOUs). These comments are limited to the sections in the Ruling related to the energy sector, and specifically sections 1 and 5 related to COVID-19 arrearage relief programs for electric utility and CCA customers.[2] CalCCA previously addressed section 3 of the Ruling and E-mail Ruling regarding CCA customer arrearages and the allocation between IOUs and CCAs of partial payments on past due accounts in its Motion to Modify Scope to Conform to Government Code §16429.5, filed August 25, 2021,[3] and its Brief on Scoped Issue 7, Allocation of Payments on Arrearages for CCA Customers, filed August 27, 2021.[4]

As set forth more fully below, the California Department of Community Services and Development (CSD) is currently administering the California Arrearage Payment Program (CAPP) that will allocate nearly $700 million of arrearage relief for energy utility and CCA customers. CalCCA requests that the Commission allow the CAPP program to be completed prior to making any further determinations on additional COVID-19 arrearage relief programs. Once the CAPP allocations are complete, the magnitude of remaining arrearages can be

[2] The Ruling originally requested Comments on sections 1, 3, 4, and 5 by September 13, 2021, but the Email Ruling provided a correction requesting Comments on sections 1, 2, 4 and 5 by September 13, 2021. *See* Ruling at 10; *see also* Email Ruling at 3. Section 2 requests comments from water stakeholders only, and therefore CalCCA provides no comments on section 2. *See* Ruling at 6. In addition, section 4 requests comments regarding coordination between water and energy utilities concerning COVID-19 relief and affordability, and CalCCA has no comment on the section 4 issues.

[3] *California Community Choice Association's Motion to Modify Scope to Conform to Government Code §16429.5,* Rulemaking (R.) 21-02-014 (Aug. 24, 2021) (CalCCA Motion).

[4] *California Community Choice Association's Brief on Scoped Issue 7, Allocation of Payments on Arrearages for CCA Customers,* R.21-02-014 (Aug. 27, 2021) (CalCCA Issue 7 Brief).

ascertained, and the Commission can determine if additional programs should be established other than the COVID-19 payment plans created by Decision (D.) 21-06-036[5] and the Arrearage Management Program (AMP).[6] In addition, the Commission should address the process of low-income customer data exchanges between the IOUs and CSD after the CAPP Applications are submitted.

At this point in the proceeding during which the CAPP allocation is being administered by CSD, CalCCA requests that the Commission:

- Remove the Section 3/Issue 7 questions from the scope of this proceeding as they relate to the CAPP program by granting CalCCA's Motion to Modify Scope to Conform to Government Code §16429.5 in order to prevent the delay of the CAPP funding for CCA customers in need;

- In the absence of a ruling on, or a denial of, CalCCA's Motion, grant the requests in CalCCA's Brief on Scoped Issue 7, Allocation of Payments on Arrearages for CCA Customers, to complete the Commission's consideration of Section 3/Issue 7 by September 30, 2021 and find that the CAPP allocation and pro rata allocation of partial payments on past due accounts between IOUs and CCAs are in accordance with Government Code sections 16429.5(f) and (g)(4);

- Refrain from implementing any further COVID-19 arrearage relief programs until the CAPP funding is allocated and the magnitude of remaining arrearages is ascertained; and

- Examine the process of customer data exchanges between CSD and the IOUs after the CAPP Applications are submitted.

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5 D.21-06-036, *Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* R.21-02-014 (June 24, 2021).

6 D.20-06-003, *Phase 1 Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Large California-Jurisdictional Energy Utilities,* R.18-07-005 (June 11, 2020) (creating the AMP to assist customers on California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) with large unpaid arrearages).

II. THE COMMISSION SHOULD GRANT CALCCA'S MOTION TO MODIFY SCOPE TO CONFORM TO GOVERNMENT CODE SECTION 16429.5 TO PREVENT DELAY OF THE CAPP PROGRAM FUNDING

CalCCA previously addressed section 3 of the Ruling and E-Mail Ruling in the CalCCA Motion and the CalCCA Brief. Section 3 addresses the questions posed in Issue 7 of the Scoping Memo regarding (1) whether and how to allocate arrearage relief to CCA customers, and (2) how to allocate partial payments on past due accounts between IOUs and CCAs.[7] CalCCA's Motion requests that Issue 7 be removed from this proceeding to the extent the questions pertain to CAPP, as CSD has jurisdiction over the CAPP program. The Commission has not yet ruled on the Motion. CalCCA requests in its subsequently filed Brief on Section 3/Issue 7 that in the absence of a ruling on or a denial of CalCCA's Motion, the Commission accelerate its schedule to complete its consideration of Issue 7 by September 30. CalCCA further requests in the Brief that the Commission make findings that the CAPP allocation and pro rata allocation of partial payments on past due accounts between IOUs and CCAs are in accordance with Government Code sections 16429.5(f) and (g)(4). The requests in CalCCA's Motion and CalCCA's Brief are intended to allow the CAPP process to proceed without any overlapping Decision by the Commission, which could interrupt and/or delay the allocation of CAPP funding to customers in need.

III. THE COMMISSION SHOULD REFRAIN FROM ENGAGEMENT IN THE CAPP PROCESS

CalCCA's comments on sections 1 and 5 of the Ruling specifically request that the Commission refrain at this time from making decisions on or implementing any further COVID-19 arrearage relief programs until the CAPP program allocation is completed. CalCCA provides comments below to the questions in the Ruling regarding: (1) the status of the CAPP process; (2)

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7 *Assigned Commissioner's Scoping Memo and Ruling,* R. 21-02-014 (Mar. 15, 2021) at 6-7.

what need will remain for arrearage relief after the CAPP funding is allocated, and how such arrearage relief should be addressed; and (3) whether any further action should be taken to address the process of the exchange of low-income customer data between the IOUs and CSD for purposes of CAPP funding disbursement.

A. The Commission Should Refrain from Implementing Any Further COVID-19 Arrearage Programs Until the CAPP Funding Program Is Completed

The CAPP program is currently being administered by CSD to allocate arrearage relief for utility customers. Assembly Bill (AB) 135 was signed by Governor Newsom on July 16, 2021, enacting CAPP and delegating oversight of the CAPP program to CSD pursuant to Government Code section 16429.5.[8] The CAPP program is a comprehensive scheme for CSD to allocate $694,953,250 to "all distribution customers of investor-owned utilities, <u>including customers served by a CCA.</u>"[9] Government Code section 16429.5(g) requires the utilities to:

> credit funding received through CAPP against customer charges owing the utility and <u>all other load serving entities</u> serving the customer in proportion to their respective shares of customer arrearages.[10]

Energy utilities will apply for CAPP benefits on behalf of eligible customers. A credit will be automatically applied to eligible customer bills once the allocations of the CAPP funding are made. Customers eligible for CAPP funds include those who incurred a past due balance of 60 days or more on their energy bill during the period covering March 4, 2020 through June 15, 2021. Government Code section 16429.5(f)(1) requires the prioritization of customers with past

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[8] AB 135, Section 9 (adding Article 12 (the CAPP Program) under the American Rescue Plan Act of 2021, to Section 16429.5 of the California Government Code) (July 16, 2021). *See* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB135.

[9] Cal. Gov. Code §16429.5(d)(2) (emphasis added). $298,546,750 of the funding will be allocated to publicly owned utilities and electric cooperatives. *Id.* §16429.5(d)(1).

[10] *Id.* §16429.5(g) (emphasis added).

due balances in the following order: (1) active residential customers at risk of disconnection; (2) active residential customers; (3) inactive residential customers; and (4) commercial customers.[11]

CSD has issued four Program Notices containing details and a schedule for the four phases of the CAPP Program:[12]

- Phase 1, Utility Survey: Utilities complete a CSD survey requesting eligible utility and CCA residential and commercial customer arrearage information by September 16, 2021. After review and verification of the utility survey information regarding a CCA's customers, that CCA must sign and provide to CSD by September 16, 2021 an attestation verifying the CCA customer arrearage information.

- Phase 2, CAPP Application: After CSD's review of the utility surveys, CSD will release statewide utility and CCA CAPP allocations, and a CAPP Application for utilities to submit to CSD on behalf of eligible utility and CCA customers to receive that allocation. Applications are due within 60 days of the (likely early October 2021) release of the CAPP Application by CSD (therefore Applications will likely be due in early December 2021).

- Phase 3, CAPP Awards: Upon approval of a utility CAPP Application, CSD will disburse the CAPP allocation award to the utility applicant (no later than January 31, 2022). Utility customers will then receive credits on their utility and CCA arrearages within 60 days of a utility receiving the CAPP funds (by late March 2022). CSD has indicated in meetings with the IOUs and CCAs, however, that it will process applications on a rolling basis to the extent a utility submits its application before the Application deadline.

- Phase 4, Outcomes Reporting: Utilities will provide documentation as requested by CSD to assist in preparing CSD's final CAPP report to the Legislature that outlines benefit outcomes for residential and commercial accounts assisted.

CSD is currently working closely with the CCAs and IOUs to complete the time-consuming and data intensive work in Phase 1. Pursuant to its statutory authority and mandate, CSD is working on a tight timeline to complete the CAPP allocation by January 31, 2022.

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11 Cal. Govt. Code §16429.5(f)(1).

12 *See* CAPP Program Notice No. 2021-01 (Jul. 19, 2021) (overview of four phases of CAPP); CAPP Program Notice No. 2021-02 (Aug. 2, 2021) (providing details on Phase 1, CAPP Utility surveys); CAPP Program Notice No. 2021-03 (Aug. 20, 2021) (revisions to survey requirements in Program Notice 2); CAPP Program Notice No. 2021-03-R (extending the CAPP Utility Survey submission deadline, including CAPP Attestation Forms applicable to CCAs, to September 16, 2021). The CSD CAPP Program Notices are located at https://www.csd.ca.gov/Pages/CAPP.aspx.

CalCCA requests that the Commission refrain from implementing any COVID-19 arrearage programs until the CAPP process is complete.

B. If Arrearages Remain After the CAPP Allocation is Completed, the Commission Can Then Determine Whether Additional Arrearage Relief is Necessary

The magnitude of remaining arrearages after the CAPP allocation (as well as any other arrearage relief funding) will not be known until CSD determines the allocations, disburses the funds, and the utilities credit customer accounts. As described above, the CAPP allocation of funds will be prioritized among four customer groups. Whether all customer groups will be allocated CAPP funds is unclear at this point.

CalCCA requests that the Commission refrain from ordering or implementing any additional COVID debt relief until the CAPP process is complete pursuant to Government Code section 16429.5(e) requires CSD to complete the process by January 31, 2022. If COVID-19 arrearages remain at that time, the Commission can determine whether existing payment plans, including the COVID-19 payment plans and the AMP, are sufficient or whether additional relief is necessary.

C. The Commission Should Refrain From Examining the Process of Customer Data Exchanges Between CSD and the IOUs Until After the CAPP Applications are Submitted

At this point, the Commission should not take action to address the process of customer data exchanges between the IOUs and CSD for purposes of CAPP funding disbursement. The IOUs are mid-course in the data sharing process for CAPP, and formal intervention by the Commission could slow the process being administered by CSD. Following the completion of Applications, however, the Commission should take the opportunity to conduct a "lessons learned" workshop to review the data exchange process between CSD and the IOUs, and the IOUs and the CCAs.

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments set forth herein.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

September 13, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS IN RESPONSE TO E-MAIL RULING REQUESTING COMMENTS ON MARKET PRICE BENCHMARK ISSUE DATE

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On behalf of
California Community Choice Association

September 13, 2021

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS IN RESPONSE TO E-MAIL RULING REQUESTING COMMENTS ON MARKET PRICE BENCHMARK ISSUE DATE

The California Community Choice Association[1] ("CalCCA") submits the following opening comments in response to the questions posed in Administrative Law Judge ("ALJ") Wang's August 25, 2021 E-mail Ruling ("Ruling") in the above-captioned proceeding.[2] The questions address further analysis from Energy Division Staff's May 20, 2021 proposal to revise the publication date for the Power Cost Indifference Adjustment ("PCIA") Market Price Benchmarks ("MPBs") from November 1 to October 1 of each year ("Staff Proposal").[3]

The analysis served on August 25, 2021 ("Staff Analysis"), while inconclusive, supports prior assertions from staff and parties that the impact of the Staff Proposal to change from a November Update to an October Update is likely to be minor. The only data permanently "lost"

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] Rulemaking (R.) 17-06-026, *E-mail Ruling Requesting Comments On Market Price Benchmark Issue Date* (August 25, 2021).

[3] R.17-06-026, Energy Division Staff, *Revision of the of the Power Cost Indifference Adjustment Market Price Benchmarks Calculation Date from November 1 to October 1 of each year* (May 20, 2021) ("Staff Proposal").

in the MPB framework will be part of the calculations for the *final* MPBs, which will now exclude transactions concluded in September for the balance of the same year; historically, a small percentage of such transactions. While other impacts, including most of the sensitivities staff ran in its analysis, may increase or decrease PCIA rates in the near term, such changes cannot be predicted with certainty, and all will be trued up with actual data the following year.

While the impacts of Staff's policy are likely to be small, the only analysis that can bring certainty to the question of the extent of those impacts is a *post hoc* analysis. Therefore, CalCCA recommends the Commission include a review of the policy's impacts at least two years after it has been enacted in any decision adopting the proposal to determine whether the policy should be revisited.

More importantly, the bigger and more critical impact of Staff's proposal to move the update forward by one month will be to the already truncated, pre-update process in the ERRA proceedings. As discussed at the June 4, 2021 workshop ("Workshop"), and within CalCCA's June 15 comments ("June 15 Comments") and June 22 reply comments ("June 22 Reply Comments") on these same issues, the Staff Proposal can address the underlying problems with the ERRA forecast timelines, while improving community choice aggregators' ("CCAs") and other parties' ability to effectively participate within the proceedings, if the Commission:

- Maintains the current, typical procedural framework for the ERRA forecast proceedings that occur prior to each year's update; and
- Requires SCE and PG&E to file their ERRA forecast applications on May 1 each year instead of June 1, or, at the very least, on a filing date in the first half of May.

A proposed decision adopting the Staff Proposal without these corresponding procedural changes must be rejected. The obstacles to effective participation in these cases are too tall. Substantive policy issues, as many as five sets of utility testimony, and constant discovery disputes all must be addressed and resolved within seven months within each proceeding. Intervenors simply cannot exercise their rights to investigate the rates their customers will pay if an entire month of the pre-update procedural schedule is excised to accommodate Staff's Proposal.

I. REVIEW OF WORKSHOP HIGHLIGHTS

ALJ Wang's Ruling poses the following question with regard to a document summarizing the June 4 workshop addressing Energy Division's MPB proposal ("Workshop"):

> 1. *Please review the attached workshop highlights prepared by Energy Division staff (including corrections to the staff proposal). Do you have any corrections or refinements to the workshop highlights?*

Per CalCCA's notes and recollections, the due process concerns in the "workshop highlights" document overstate the depth and breadth of that discussion at the Workshop, which formed a much smaller portion of the workshop's time than that document suggests. Moreover, for the reasons stated within the June 15 Comments, the due process question is narrow and easily addressed in this instance, especially on account of the PCIA service list including most of the "usual suspects" that participate in the ERRA forecast proceedings, including the utility applicants, various CCA parties, direct access groups, The Utility Reform Network, the agricultural parties, and CalAdvocates. Reviewing the service list from the 2021 ERRA forecast proceedings for the past several years reveals few parties that are not on the PCIA service list. However, as discussed in the June 15 Comments, moving the application date forward should only assist intervenor parties, not inhibit them.

In recognition that such changes are already in scope in this case and can be addressed without raising significant due process issues, the ALJ ruling correctly takes on the issue of the ERRA forecast application deadline. However, language in the "workshop highlights" addressing the limitations on scope appear to contradict this conclusion and should be refined. Specifically, the following sentence in the fourth bullet on page 1 should be revised to state:

"~~Because some~~ While few stakeholders in the ERRA proceeding are not included in the PCIA service list, ~~the~~ changes regarding the fiscal structure of the GRC and ERRA rate changes ~~considered by the Alternate Proposal~~ pose ~~significant~~ sufficient issues of due process that the Commission should not consider in this proceeding changes to the January 1st target date for rate implementation. However, the Commission should reconsider whether the proceedings can begin sooner to accommodate Staff's Proposal while maintaining existing procedural timelines."

Further, and for the same reasons, in the last sentence on page one, the phrase "while the ERRA schedule is not within scope" should either be (1) deleted, (2) clarified to only address the specific dates each judge will determine as part each case's procedural schedule (apart from the application date in ALJ Wang's ruling and the general framework described below in these comments), or (3) qualified as a staff assertion rather than an acknowledgement.

II. ENERGY DIVISION ANALYSIS OF THE IMPACT OF STAFF'S PROPOSAL

ALJ Wang's Ruling poses the following question with regard to Energy Division's analysis of the impact of Staff's Proposal:

> *2. Please review the attached analysis by Energy Division staff of the impact of changing the issue date of the Market Price Benchmark calculations on the annual PCIA calculations in the ERRA forecast proceedings.*
>
> > *a. Do you agree with the conclusion of the staff analysis that the impact of implementing the May 2021 staff proposal on Market Price Benchmark calculations and PCIA rates appears to be minor? Why or why not?*
> >
> > *b. What is a reasonable expectation (in percentage terms) for changes to the energy index as a result of using September forwards instead of October forwards?*

While not conclusive, Energy Division's analysis supports the assumptions of most of the parties at the Workshop: the impact of the proposal is likely to be minor.

A. CalCCA Largely Agrees With Staff's Conclusions.

Staff was unable to complete the analysis they sought to complete, *i.e.*, to review data from the past few years and analyze how the benchmarks would have changed under the Staff Proposal.[4] Instead, the analysis states Staff conducted sensitivity analyses "by directly adjusting the values of previously calculated MPBs and then re-running PCIA calculations using these *estimated* data."[5] The results of these sensitivities are not surprising. For example, in Tables 3 and 5, if the value of the RPS and RA Adders increase, the PCIA rate in each service territory decreases.[6] The sample size of the years analyzed prevents broad conclusions, however, and the actual impacts are likely to vary from year to year.

Yet the analysis provides support to prior assertions from parties that the change from a November Update to an October Update is likely to be minor. First, the only data permanently "lost" in the MPB framework will be part of the calculations for the *final* MPBs, which will now exclude transactions in September for the balance of that same year, *i.e.*, transactions completed in September of year n for delivery in October through December of year n.[7] Historically, especially for resource adequacy, balance-of-year transactions form a small percentage of such transactions.[8] Tables 2 and 4 in the analysis clearly confirm that this impact will be small,[9] meaning the only permanent impact of the Staff Proposal appears to be minor.

The other, more major changes the report describes regarding *forecast* MPBs also do not raise substantial concerns. All of the PCIA increases or decreases presented in Tables 3, 5, and 6, including the "worst-case scenario", will eventually be trued up under the process adopted in

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4 Staff Analysis at 3.
5 *Id.* (emphasis in original).
6 *Id.* at 5, Table 3, and at 7, Table 5.
7 *Id.*at 3-6, Tables 2 and 4.
8 *Id.* at 4, 6.
9 *Id.* at 3-6, Tables 2 and 4.

D.18-10-019 and D.19-10-001. Staff correctly observes that "[a]ny increase or decrease in PCIA rates is important because it has a direct effect on electric ratepayers" but also that such impacts are likely to be mild in this case.[10] Thus, while the accuracy of the MPBs could be reduced to some extent because market data for September will not be included in the MPB until the following year, or in the case of the Final MPBs will be excluded altogether, such concerns do not override the benefits of moving up the benchmark calculation.

Nonetheless, the only analysis that can bring certainty to the question of the impacts of Staff's policy is a *post hoc* analysis conducted over the course of the next few years. For example, it is possible, although unlikely, that market participants could change their behavior in order to take advantage of the new approach, seeking to put as much value into transactions that are now lost in order to overstate the PCIA. Given the difficulty in obtaining the data Staff originally sought to conduct their analysis, CalCCA recommends the Commission collect data over the next few ERRA cycles to conduct a review of the policy's impacts after it has been enacted in any decision adopting the proposal.

Lastly, there is one error in Table 6 that should be addressed to ensure the table is internally consistent. Given the increases in the Energy Index described in the first and second columns of that table the "Percent rate change" in each of the remaining columns should be negative. Further, the PCIA rate changes illustrated in Table 6 are opposite in direction relative to the Staff conclusion discussed in the narrative above the table. That is, Staff estimates that an energy index calculated in September would be *lower* than an index calculated in October, but Table 6 illustrates the impacts of a progressively *higher* energy index.

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[10] Staff Analysis at 9.

B. Changes to the Energy Index

In order to calculate a reasonable expectation (in percentage terms) for changes to the energy index as a result of using September forwards instead of October forwards, parties require access to data from prior years that falls under a Platt's proprietary license. CalCCA was unable to obtain the necessary licenses and data in the timeline provided for these comments but reserves the right to reply to the other parties' analyses, if any, in reply comments.

III. MODIFICATION OF THE ERRA FORECAST APPLICATION DEADLINES

Regardless of the substantive impact, the procedural questions surrounding the Staff Proposal are deeply concerning for intervenor parties, and it will be important to avoid trading one set of procedural problems for another set of problems. ALJ Wang's Ruling poses the following question with regard to modification of the ERRA forecast application deadlines:

> 3. *The schedules of the ERRA forecast proceedings will be determined in each ERRA forecast proceeding. However, we will consider in this proceeding whether to change the ERRA forecast application filing deadlines.*
>
>   a. *If the Commission implements the May 2021 staff proposal, should the Commission direct any of the utilities to file its ERRA forecast application earlier?*
>
>   b. *Are there any barriers or drawbacks to earlier filing of any of the ERRA forecast applications?*

The numerous reasons Staff cited at the Workshop as support for revising the MPB publication dates are irrefutable,[11] with many having been raised by CCA parties in the utilities' individual ERRA forecast proceedings in recent years.[12] Moving the MPB publication from late October to

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[11] R.17-06-026, *Commission Staff Presentation, Energy Division Workshop on the PCIA Market Price Benchmark Release Date*, slides 6, 8 (June 4, 2021).

[12] *See, e.g.*, A.19-06-001, *Protest of the Joint CCAs to the Application of Pacific Gas and Electric Company (U 39 E) for 2020 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast And Greenhouse Gas Forecast Revenue Return And Reconciliation*, pp. 26-29 (July 5, 2019).

late September, thereby replacing the "November Update" with an "October Update", will give the Commission and parties sufficient time to reach a reasoned decision, without the need to stipulate to shortened timelines subsequent to the October Update, in time for January 1 implementation. However, the Staff Proposal should be adopted only if the PG&E and SCE application dates move forward, and the SDG&E application date remains on or before May 15, allowing the existing procedural timelines between the application date and reply briefs to be kept.

A. The Commission Should Direct the IOUs to File Their Applications on May 1 or in the First Half of May.

The CCAs' underlying issue for the ERRA forecast proceedings has been, and continues to be, the compression of the cases' procedural schedules. While CalCCA proposed moving the November Update timeline up one week as part of its comments in January, the CCAs did not support moving it up a full month. Presently, there is insufficient time to fully vet each part of the ERRA forecast cases. If the ultimate resolution the Commission reaches is to shift some of the schedule compression from one part of the proceeding to another, such a resolution would fail to address the CCAs' underlying concerns.

1. Revisions to the MPB Publication Date Should Avoid Trading One Set of Procedural Problems for Another.

CalCCA's June Comments provided the following as a schedule framework to help illuminate the concerns with simply deleting one month of the pre-update schedule, with the major milestones highlighted in blue:

Date	Procedural Step
April 15	SDG&E files its Application[13]
May 1	PG&E and SCE file their Applications
Early June	Protests to Applications due
Mid-June	Replies to Protests due and Prehearing Conference
Late June/Early July	Scoping Ruling published
Early August	Intervenor testimony due
Mid-August	Rebuttal testimony due
Late August	Hearings
Mid-September	Opening briefs due
Late September	Reply briefs due
End of September	Energy Division publishes the MPBs
Early October	Updates filed
Late October	Comments on updates filed
Mid-November	Proposed Decision issued
Last Commission Business Meeting in December	Decision adopted
January 1	Rates implemented

While the judges for each ERRA forecast proceeding will ultimately decide the specific schedule for each case, providing broad guidance targeting the schedule above will accomplish the goals in the Staff Proposal without causing collateral procedural problems.

Failing to undertake this type of comprehensive revision to the ERRA forecast process, while still adopting the Staff Proposal, will cause problems in October of each year and beyond. For example, the typical procedural schedules for SCE and PG&E's ERRA forecasts utilize October for some combination of testimony, hearings, and briefing.[14] Simply moving the update forward one month will result in witnesses responsible for testimony and hearings concurrently

[13] The SDG&E procedural dates do not need to shift to accommodate Staff's Proposal. Thus, the dates in this table between May 1 and the "End of September" only apply to PG&E and SCE's cases. However, SDG&E has recently requested the Commission allow it to file future ERRA forecast applications by June 15, which would provide even less time for review than what is currently provided in the PG&E and SCE proceedings. A.21-08-010, *Application of San Diego Gas & Electric Company (U 902-E) for Approval of Its 2022 Electric Sales Forecast*, p. 8 (Aug. 13, 2021).

[14] *See, e.g.*, A.20-07-004, *Assigned Commissioner's Scoping Memo and Ruling*, p. 4 (Sept. 10, 2020); A.19-06-002, *Assigned Commissioner's Scoping Memo and Ruling*, p. 4 (Aug. 22, 2019); and A.20-07-002, *Assigned Commissioner's Scoping Memo and Ruling*, pp. 4-5 (Sept. 10, 2020).

working on (a) testimony and hearings and (b) either "October Update" testimony or comments responding to that testimony. Facts on which those witnesses may be testifying will be changing simultaneously with the publication of the updates. Discovery on the updates will coincide with discovery in preparation for hearing. Briefs will need to be written concurrently with comments on the update or somehow incorporate those comments. Judges and staff will need to analyze these various components of the record at the same time rather than in the type of sequential order that might allow for drafting of Proposed Decisions on some issues while issues related to the updates are still pending. The intense administrative burdens on Staff, judges, witnesses, and attorneys currently felt in November and December will simply switch to intensive burdens in October and November.

To avoid this result, it will be important to move the rest of the procedural schedule forward in addition to the publication of the MPBs. Implicit in the timelines between procedural steps in the table above, this approach allows parties and the Commission to complete the record on any issues unrelated to the update prior to the update being published. This staggering of issues has allowed for efficient resolution of certain issues in these proceedings over the past few years, and that efficiency is one successful part of the current process that should not be altered.

2. The Increasing Complexity of These Proceedings Warrants an Approach That "Does No Harm" to Existing Procedural Challenges.

It is critical the Commission maintain the current amount of time that exists in each proceeding prior to either an October or November update being filed. Shifting each aspect of the proceeding up by one month, while maintaining the current filing dates, will squeeze the beginning of the proceeding in two untenable ways: (1) the effect on the timing of protests, responses, prehearing conferences, scoping rulings and direct testimony and (2) the corresponding ability for intervenors to effectively prosecute these cases in light of the multiple rounds of IOUs testimony now filed in each case and the need to resolve repeated discovery disputes.

PG&E and SCE both file June 1, with protests due the first week in July., and SDG&E has asked the Commission to file on June 15 instead of April 15 in order to consolidated their load forecast proceeding with their ERRA forecast proceeding. Protests for this year's proceedings were due July 6 and July 12, in PG&E and SCE's cases respectively, with the IOUs' replies due July 16 and July 22. If the rest of the schedule shifts forward by a month, there would be only 2-4 weeks between the due date for replies and intervenor testimony, leaving a short amount of time for the Commission to hold a prehearing conference and issue a Scoping Ruling. Despite it occurring the few years prior to this year, it is deeply unfair to expect parties to draft testimony within a week or two of the issuance of a Scoping Ruling, especially in cases where disputes over scope are not uncommon,[15] and parties may not know if certain issues can be raised in testimony.

Exacerbating these procedural questions is the fact that a substantial amount of work is done in these proceedings prior to the updates, including ratemaking, policy and implementation work the Commission has punted to these cases from other cases, including prior ERRA forecast cases. Examples of these issues in just the past few years include:

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[15] *See, e.g.*, A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner*, p. 4 (Sept. 12, 2013) (rejecting the inclusion of certain issues in scope and finding that policy issues and other industry-wide practices such as changes to the PCIA methodology are properly addressed in rulemaking dockets, such as R.17-06-026); A.17-06-005, *Scoping Memo and Ruling of Assigned Commissioner*, pp. 3-4 (Aug. 24, 2017) (finding certain issues raised in protests would constitute changes to existing methods of calculation and not allegations of non-compliance with Commission rules, decisions, and resolutions on the part of PG&E); A.18-06-001, *PG&E Reply to Protests and Responses*, pp. 2-3 (July 16, 2018) (arguing issues the Joint CCAs raised in their Protest issue are out of scope, including that "challenges to the Commission's existing policy and/or rules are beyond the scope of this proceeding and must be raised via a petition for modification of the decision that established the policy and/or rule in question.").

For PG&E:

- The methodology to refund a Cost Allocation Mechanism ("CAM") misallocation;[16]
- The methodology to return ERRA overcollections in an equitable manner;[17] and
- The methodology to calculate the RA component of GTSR rates.[18]

For SDG&E:

- The right billing determinants to reflect departing load when setting 2021 rates;[19] and
- Questions regarding the correct rate to form the basis for the PCIA rate cap.[20]

All three IOUs:

- Implementation of changes to the methodology used to calculate the PCIA from D.18-10-019 and D.19-10-001;[21]
- Questions surrounding funding for the Solar on Multi-family Affordable Housing program;[22] and
- Issues related to transparency and data access.[23]

It is unlikely the need to resolve ratemaking, policy and implementation issues will diminish. This year, the parties to PG&E's ERRA forecast case will need to address the accounting treatment for PG&E's "emergency" Green Tariff Shared Renewables ("GTSR") Petition for Modification ("PFM"), if granted, and the utility's proposal to shift certain Public Purpose Program ("PPP")-related costs out of the non-vintaged PCIA and into the PPP.[24] These significant policy issues require a thorough examination over an already truncated period.

Going forward, the ERRA forecast proceedings will continue to modify the PCIA methodology, and other Commission decisions will continue to impact the forecast cases. For example, since no two parties read a Commission decision the same way, implementation of the Voluntary Allocation and Market Offer component of the Commission's Working Group 3

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16 D.20-02-047 at 10.
17 *Id*. at 11-12.
18 D.20-12-038 at 28-29.
19 D.21-01-017 at 42-44.
20 *Id*. at 34-38.
21 *See, e.g.*, D.18-10-019 at Ordering Paragraphs ("OPs") 8 and 10; D.19-10-001 at OPs 2-4.
22 *See* D.17-12-022 at OP 4.
23 D.20-12-035 at OP 8; D.20-12-038 at OP 4; D.21-01-017 at OP 6.
24 A.21-06-001, *Assigned Commissioner's Scoping Memo and Ruling*, p. 4 (Aug. 1, 2021).

decision, D.21-05-030, is likely to introduce new implementation issues for the 2023 ERRA forecast case. In addition, recent RA decisions are almost certain to introduce new accounting issues to both the 2022 and 2023 ERRA forecast proceedings, *e.g.*, ensuring that if existing resources are procured by the Central Procurement Entity (D.20-06-002), to meet 2021 summer reliability targets (D.21-02-028), or to meet the incremental procurement targets 2021-2023 (D.19-11-016), they are accounted for correctly in the CAM balancing accounts, Modified CAM balancing accounts and the Portfolio Allocation Balancing Account. In sum, significant policy and implementation issues are frequently addressed in these proceedings, and the loss of a month of pre-update litigation will undermine parties' ability to address these issues and, in turn, diminish the adequacy of the record upon which the Commission relies to address them.

Further burdening the ERRA forecast cases, the filing of three to five sets of utility testimony has become commonplace. These rounds of testimony are frequently the result of parties and the Commission needing to better understand or incorporate recently completed proceedings that impact the forecast cases. SCE just filed supplemental testimony on September 10, 2021 to incorporate its August general rate case decision.[25] Notice to the CCAs of this supplemental testimony was provided in a discovery request response.[26] In addition to its prepared testimony and its November Update, there are now three rounds of utility testimony in that case, two before intervenor testimony, with this supplement provided less than three weeks before intervenor testimony is due.

PG&E, without providing any prior notice to parties, filed supplemental testimony in this year's ERRA Forecast on September 2nd, just before the Labor Day weekend and also less than

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[25] A.21-06-003, *Supplemental Testimony Supporting Southern California Edison Company's Application For Approval of Its 2022 ERRA Forecast Proceeding Revenue Requirement* (Sept. 10, 2021).

[26] A.21-06-003, *SCE Response to SoCal CCAs 2.07* (July 29, 2021).

three weeks before intervenor testimony is due.[27] This supplemental testimony included significant changes to the original application, and the timing and lack of notice restricts parties' ability to review such changes.[28] PG&E will end up filing four sets of testimony in this case, due to the supplemental testimony that had already been filed on August 25.[29] This is not uncommon. PG&E submitted *five versions* of testimony over the course of last year's case, Application (A.) 20-07-001, including its prepared testimony and the November Update.[30]

Further, while they only sometimes rise to the level of commanding a judge's attention, discovery disputes abound in these proceedings. The utilities frequently object to discovery requests, requiring intervenors to spend the time and resources necessary to navigate such disputes. For example, last year SCE initially refused to provide the RA and RPS-eligible volumes it forecasted would remain unsold in the forecast year, 2021. The parties met and conferred, and resolved the issue, but nearly 1.5 months passed between the SoCal CCAs' July 20, 2020 original data request and the final supplement to SCE's first responses, which were provided on September 1, 2020.[31] Sometimes untenable objections are walked back once opposing counsel question the objection, again requiring an unnecessary, intermediate step (and delay) to obtain discoverable information. In this year's case,[32] the SoCal CCAs have faced repeated requests for an extension of time in responding to discovery requests. Even after an

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[27] A.21-06-001, *Pacific Gas and Electric Company 2022 Energy Resource Recovery Account and Generation Non Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Supplemental Testimony* (Sept. 2, 2021).

[28] *Id.* at 1-2.

[29] A.20-07-001, *Assigned Commissioner's Scoping Memo and Ruling*, p. 4, (Aug. 11, 2021).

[30] *See, e.g.*, A.20-07-002, *Protest of the Joint CCAs to the Application of Pacific Gas and Electric Company*, p. 6 (Aug. 5, 202).

[31] *See* A.20-07-004, *Joint Opening Brief of the Clean Power Alliance of Southern California and California Choice Energy Authority (The "SoCal CCAs") and the California Community Choice Association*, pp. 14-15 (Oct. 26, 2020).

[32] A.21-06-003, *Application of Southern California Edison Company (U 338-E) For Approval of Its 2022 ERRA Forecast Proceeding Revenue Requirement* (June 1, 2021).

extension is agreed upon, SCE's responses sometimes require supplemental data requests to obtain straightforward responses or clarifications.

Similar disputes have plagued PG&E's and SDG&E's proceedings.[33] While the CCAs have hoped the Commission's recent decisions regarding data access and transparency would ease these tensions,[34] PG&E refused to provide confidential data to the Joint CCAs' reviewing representatives for weeks, delaying their ability to review confidential workpapers. The utility is also refusing to provide basic data in this year's case that PG&E provided in last year's, requiring the Joint CCAs to file a motion to compel to simply gain access to the same data the CCAs need to draft their testimony that the utility had in drafting its testimony.[35]

In SDG&E's case, SDG&E simply refused, without initially offering an objection, to provide certain baseline data supporting current PCIA rates in its discovery responses. The CCA Parties were forced to meet and confer with SDG&E before it ultimately explained its objection, eventually requiring the CCA Parties to file a motion to compel. While the judge ultimately denied the CCA Parties' motion, he provided very limited explanation for doing so. The importance of these data and the challenges posed by SDG&E's obstinacy in refusing to provide them are described in the CCA Parties' testimony in A.21-04-010, and parallel issues experienced by other CCAs in the other IOUs' forecast case will be raised in testimony in the hopes of achieving a consistent result across all IOUs that ensures parties have the data they need to ensure the rates their customers pay are just and reasonable.

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33 *See, e.g.*, A.19-06-001, *Motion to Compel of the Joint CCAs*, pp.1-10 (Nov. 11, 2019); A.21-04-010, *Motion to Compel Discovery of San Diego Community Power and Clean Energy Alliance*, Exhibit C (June 16, 2021).

34 D.20-12-035 at OP 8; D.20-12-038 at OP 4; D.21-01-017 at OP 6.

35 A.21-06-001, *Motion to Compel Discovery of the Joint CCAs*, pp. 1-3 (Aug. 31, 2021).

SDG&E also takes an extreme approach to redacting its PCIA data under the guise of D.06-06-066 and provides only the most superficial of justifications for such redactions. When ordered by the judge to supplement its justifications, SDG&E withdrew some of its confidentiality designations, but maintains an overbroad confidentiality approach, particularly in comparison to the other two IOUs.[36] Redacting such large portions of the PCIA places arbitrary limitations on the ability of the CCAs' attorneys and experts to communicate with their clients, but challenges to confidentiality designations under D.06-06-066 are extremely complex, causing a significant drain on the resources of parties.

The CCAs continue to pursue these issues in these individual cases, as necessary. However, they provide clear evidence of the types of unnecessary and frustrating disputes intervenors continue to face in getting timely access to relevant data. These disputes only add to parties' burdens of addressing policy issues and keeping up with multiple rounds of testimony prior to intervenor testimony being due. Parties will not be able to litigate these cases if one month of the schedule is simply excised.

B. The Barriers or Drawbacks to Earlier Filing of the ERRA Forecast Applications that the IOUs have Identified Are Easily Addressed.

While it is clear the pre-update timelines of these cases should shift forward, such a shift must also accommodate the timing of load forecast data. SCE's Petition for Modification, filed in R.01-10-024 ("SCE PFM"), resulted in that utility's current June 1 filing date.[37] The purpose of moving from May 1 to June 1 was to incorporate more accurate departing load forecasts, provided in April as a result of Resolution E-4907, which modified the process and timeline by

[36] A.21-04-010, *San Diego Gas & Electric Company's (U 902-E) Notice of Compliance with Ruling Denying Motion to Compel Public Disclosure of Information Designated as Confidential* (July 22, 2021).

[37] D.18-10-042 at 4 and Ordering Paragraph 2; *see also* R.01-10-024, *Petition for Modification of Southern California Edison Company (U 338-E) of Decision 14-05-006 to Establish New Filing Date For Its Annual ERRA Forecast Application* (Aug. 3, 2018).

which CCA load forecasts and RA obligations are determined.[38] Moving the update back a month squeezes the proceeding up against that mid-April load forecasting date.

The IOUs' filings undoubtedly are better with the most accurate CCA departing load information. However, the vast majority of load departures in major metropolitan areas have already taken place in California, or will take place in the next year. If load forecasts need to be modified, those modifications are likely to be less dramatic than those experienced over the past few years in the State, suggesting the "October Update" filing itself could accommodate changes brought on by newly departing load.

On balance, a May 1 filing date for SCE and PG&E would be the ideal date to accomplish Energy Division's goals while preserving the current pre-update timelines. The IOUs' June 22 reply comments include a cursory response to CalCCA's concerns, summarizing the reasoning behind SCE's move to June 1 and stating:

> An annual May 1st filing date would be incompatible with PG&E's obligations concerning presenting a load forecast and, to the extent SDG&E is required to address load forecasting in its annual ERRA filing, it will need more, not less, time to develop this additional input into its ERRA Forecast application. [39]

As stated in CalCCA's June 15 Comments, if the CCA load forecasts cannot be incorporated by a May 1 filing date, and the Commission determines the update filing is an inappropriate vehicle to incorporate the CCAs' mid-April load forecasts, then a filing date in the first half of May for SCE and PG&E would also make sense.

The Joint IOUs June 22 reply comments do not put forward a workable compromise on timing, or even give credence to the Joint CCAs' concerns. Changes that would result in *less*

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38 D.18-10-042 at Finding of Fact 2.

39 R.17-06-026, *Joint Reply Comments of Southern California Edison Company (U 338 E), Pacific Gas and Electric Company (U 39 E) and San Diego Gas & Electric Company (U 902 E) On the Energy Division Staff Proposal Concerning the Timing Of The Market Price Benchmarks*, p. 2 (June 15, 2021).

time for intervenors to analyze the application, or could lead to more issues being scoped into these proceedings, are almost certain to be more harmful than helpful. The Joint IOUs' request to modify standard procedural timelines for protests and replies appears aimed at reducing the time allowed for those procedural mechanisms.[40]

Similarly, establishing a "set" procedural scope supporting January 1 rate implementation,[41] with additional issues as part of a second procedural track in each case, could open the floodgates to even more policy issues being considered in these recurring cases. Prolonged litigation that increases costs for intervenors, and the potential for multiple, off-cycle, rate changes that increase rate uncertainty, weigh heavily against such an approach. The Commission already has the ability to create parallel tracks in ERRA proceedings, as appropriate, and has done so, including the original PCIA working group that led to the Commission instituting the instant proceeding,[42] or the Phase 2 in PG&E's 2017 ERRA forecast proceeding to address cost responsibility for pre-2009 direct access customers.[43]

The oft-repeated chorus from the IOUs, which is included in the Joint IOUs' June 15 comments, is that these cases, and particularly the November Update, are formulaic and mechanical ignore reality and are unhelpful.[44] The CCAs, both in the ERRA forecast proceedings and throughout this proceeding, have refuted this position time and again, and the IOUs' repeatedly short memories on the intense efforts and disputes that recur both before and in

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40 Joint IOU Comments at 4.

41 *Id.*

42 A.14-05-024, *Southern California Edison Company's (U 338-E) Submission of the Final Report of the PCIA Working Group*, p. 1 (April 5, 2017) (implementing D.16-09-044 on behalf of SCE and Sonoma Clean Power Authority).

43 D.19-12-010 at 1.

44 R.17-06-026, *Joint Opening Comments of Southern California Edison Company (U 338 E) and Pacific Gas and Electric Company (U 39 E) on the Energy Division Staff Proposal Concerning the Timing Of The Market Price Benchmarks*, pp. 1-2, n. 2 (June 15, 2021).

November each year must be given little weight. The CCAs have found hundreds of millions of dollars of errors and unfair policies in these cases in the past five years. The IOUs' real concern seems to be that a group of motivated and well-equipped parties are now paying close attention to these cases; have the right to access the same data the IOUs have when putting together their applications; have exercised those rights to the limited degree allowed by the Commission's onerous confidentiality requirements; and have had some success in identifying the IOUs' errors and refuting unreasonable policy proposals aimed at solely benefitting the IOUs. In response, and at every turn, the IOUs have attempted to make these proceedings more difficult for intervenors to litigate, and the Commission should not tolerate such advocacy.

IV. CONCLUSION

CalCCA respectfully requests the Commission adopt the Staff Proposal commensurate with the recommendations herein with the requirement that SDG&E, PG&E and SCE all file their applications on or earlier than May 1 or, at the very least, a date in the first half of May.

Respectfully submitted,

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On behalf of
California Community Choice Association

September 13, 2021

CALCCA
ADVANCING LOCAL ENERGY CHOICE

September 13, 2021

VIA ELECTRONIC MAIL

Mr. Edward Randolph
Executive Director for Energy and Climate Policy
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: Protest of the California Community Choice Association of *Joint Tier 2 Advice Letter of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company to Propose Load Forecasting and Renewables Portfolio Standard Methodologies for Voluntary Allocation of the RPS Attributes of the Power Charge Indifference Adjustment Eligible Portfolio*

Dear Mr. Randolph:

Pursuant to the California Public Utilities Commission's (Commission) General Order (GO) 96-B,[1] the California Community Choice Association[2] (CalCCA) submits this protest of Southern California Edison Company's (SCE) Advice Letter 4569-E, Pacific Gas and Electric Company's (PG&E) Advice Letter 6305-E, and San Diego Gas & Electric Company's (SDG&E) Advice Letter 3835-E (Advice Letter), jointly submitted August 23, 2021. CalCCA requests that the Energy Division limit any approval of the Advice Letter to the scope defined in Decision (D.) 21-05-030, deferring other issues to resolution in the implementation process. CalCCA's protest offers the following recommendations:

- ✓ Limit the scope of the Advice Letter approval to the mechanics of the share and product allocation, consistent with Ordering Paragraph (O¶) 16;
- ✓ Require the investor-owned utilities to file a supplemental advice letter addressing issues raised related to the allocation methodology at the September 3, 2021, workshop (Workshop);

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1 References to "General Rules" are to the general rules identified in General Order 96-B.

2 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

- ✓ Identify and correct any differences in the investor-owned utilities' (IOUs') allocation methodology as applied to bundled versus unbundled customers; and
- ✓ Ensure the details of the VAMO are timely and adequately addressed in the RPS proceeding.

With these refinements, CalCCA supports the Energy Division's approval of the Advice Letter.

RESPONSE

1. Approval of the Advice Letter Should Be Limited to the Scope of Issues Defined in Decision 21-05-030 Ordering Paragraph 16

In adopting the Renewable Portfolio Standard (RPS) Voluntary Allocation and Market Offer (VAMO) process proposed in Phase 2 of R.17-06-026, D.21-05-030 established a timeline. Among other milestones, O¶16 requires that within 90 days of its effective date:

> the IOUs should meet and confer with parties to this proceeding and jointly file a Tier 2 advice letter to propose (i) a methodology for calculating potential Voluntary Allocation shares based on vintaged, annual load forecasts, and (ii) a methodology for dividing their RPS portfolios into shares to be allocated. IOUs should host a joint workshop within 14 days of filing the advice letter to discuss the proposed methodologies.[3]

As directed, the IOUs met and conferred with parties to this proceeding, offering a presentation on their proposed methodology. With virtually no change in their proposal, they jointly filed the Advice Letter on August 23, 2021, and held a workshop on September 3, 2021.

Despite the scope of issues defined in D.21-05-030, the Advice Letter goes beyond O¶ 16, addressing issues other than the mechanics of the portfolio and share allocations. Specifically, the Advice Letter describes the calculation of payments for allocated shares, the timing of payments, and the calculation of the payment true-up.[4] Most strikingly, and to the surprise of Working Group 3 co-lead CalCCA, the Advice Letter provides that the "payment owed for the RPS Allocation would be calculated and due upon the LSE's election…."[5] While SCE clarified during the workshop that payment for a full year in advance was not its intent, payment, credit, and collateral should not be at issue in the Advice Letter.

In addition to payment, the Advice Letter addresses the timing of transfers of RPS energy[6] and downstream restrictions on further allocation or sale of the products. Neither of

[3] D.21-05-030, Ordering Paragraph 16, at 62.
[4] Advice Letter at 6-7.
[5] *Id.* at 6.
[6] *Id.* at 7.

these issues were addressed in the IOUs' meet and confer processes with load-serving entities (LSEs) in advance of the Advice Letter submission, nor were they addressed in the IOUs' workshop presentation.

This expanded scope of the Advice Letter contravenes O¶ 14, which provides that the Commission will "review, approve, and monitory the RPS VAMO and RPS RFI activities through the Commission's RPS proceeding…." CalCCA agrees with the Commission's determination that details involving payment, product transfer, and downstream limitations on allocated products, and many other details are more appropriately addressed in a more rigorous process. **For this reason, to the extent the Energy Division approves the Advice Letter, it should limit its approval to the scope of the Advice Letter narrowly to O¶ 16 and defer other issues to the RPS proceeding.**

2. The IOUs Should Refine the Proposal Through a Supplemental Advice Letter Filing Addressing Issues Raised During the September 3 Workshop

The IOUs clarified a few points during the Workshop that should be included in a Supplemental Advice Letter to ensure that the allocation methodology is transparent and certain. The supplement should:

- Reconfirm that an LSE may take all of its allocation as short-term (including allocations that otherwise would be eligible as long-term) in 10% increments; and may take long-term allocations (also in 10% increments), provided that in total its accepted allocation does not exceed the amount calculated by the IOU as available for allocation to the LSE.[7];

- Confirm that the number of megawatt hours (MWh) allocated may change, depending upon the production levels of the allocated pools, but that the percentage share of the portfolio allocated to an LSE will be set once in advance of a year without later modification;

- Confirm that while the Voluntary Allocation will occur only once per compliance period, and the Market Offer for unallocated resources will be repeated annually;

[7] For example, if an LSE is allocated the opportunity to procure 100 MWh, 60 MWh of which meets the RPS-long-term eligibility requirements, the LSE could choose to take all 100 MWh as a short-term allocation in 10% increments. The LSE could also take its long-term resources in 10% increments provided it did not exceed its allocated amount. An LSE taking 70% of its allocation short-term (70 MWh) in this example, would be limited to taking up to 50% of its long-term allocation (50% of 60 MWh) to stay within its total allocation of 100 MWh. Only resources taken through the long-term allocation count towards the LSE's long-term requirement.

- Explain whether any changes in the resources included in the short- and/or long-term pool can change during the course of an allocation year and, if so, how and when notice will be provided to LSEs who have received the allocations;

- Confirm that while evergreen contracts and utility owned generation resources will be excluded from the calculation of the term of commitment for a long-term allocation, these resources will still be included in the long-term allocation pool; and

- Disclose whether any PURPA contracts have been modified to provide RPS attributes and, if so, whether they will be included in the VAMO.

Any other clarifications or changes identified as a result of the workshop should also be included in the Supplemental Advice Letter.

3. Treatment of IOU Bundled Customers Must Be Addressed Clearly in the VAMO Allocation Methodology

Questions arose during the Workshop regarding how the VAMO procedures will apply to IOU bundled customers. Parties appropriately questioned whether long-term contracts with fewer than ten years remaining in their term would lose their long-term value if retained by bundled customers to bring parity with the allocation to other LSEs. For other LSEs, long-term contracts with less than 10 years remaining will be treated as short-term.[8] Similarly, questions arose regarding how IOU bundled allocation will be handled if any portion of the allocation is rejected by the IOU. The Commission must address these and other issues regarding parity between bundled and unbundled customers in the VAMO process in the RPS proceeding.

4. The Energy Division Should Ensure the Details of the VAMO are Timely and Adequately Addressed in the RPS Proceeding

While not at issue in this Advice Letter, CalCCA observes that the RPS proceeding schedule will create serious challenges to LSEs seeking to participate in the RPS Voluntary Allocation. The schedule will not permit participating LSEs to know the full terms and conditions of an allocation before they are required to commit. Most critically, the contract form and other key terms and conditions must be final ***before*** LSEs can reasonably be expected to make their elections final in May 2022.

Other issues must also be timely addressed in the RPS proceeding – some of which may be a part of the contract. For example:

- What data and level of granularity will be provided to participating LSEs in advance of their election? At a minimum, when the available allocations are identified in February 2022, they must include a forecast of how a long-term

[8] D.21-05-030 at 22.

allocation is predicted to change over time, a breakdown by technologies, a breakdown by product type (e.g., PCC 1), and the best available data allowing a participating LSE to understand the shape of its allocation.

- What level and types of credit and collateral will be required?
- When will settlement take place, when will production data be provided, and when will payment occur?
- How will Market Offers be structured around term, product definition, and other key features?

CalCCA looks forward to working with the Energy Division staff and the investor-owned utilities in working through these and other issues timely in the RPS proceeding.

CONCLUSION

CalCCA thanks the Energy Division for its review of this protest and requests consideration of the recommendations offered herein.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl

General Counsel and Director of Policy

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CALCCA
ADVANCING LOCAL ENERGY CHOICE

September 13, 2021

VIA ELECTRONIC MAIL

Mr. Edward Randolph
Deputy Executive Director for Energy and Climate Policy
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: California Community Choice Association's Protest to Pacific Gas and Electric Company's Tier 2 Advice Letter 6306-E -- PG&E's Methodology for Resource Adequacy Capacity Pursuant to Decision 21-05-030

Dear Mr. Randolph:

Pursuant to the California Public Utilities Commission's (Commission) General Order (GO) 96-B,[1] the California Community Choice Association[2] (CalCCA) submits this protest of Pacific Gas and Electric Company's (PG&E) Advice Letter 6306-E (Advice Letter). PG&E submitted the Advice Letter on August 23, 2021, to provide its methodology for determining how much of its Power Charge Indifference Adjustment (PCIA)-eligible resource adequacy (RA) capacity is reserved as part of its Bundled Portfolio Plan (BPP), as required by Decision (D.) 21-05-030.

For the reasons set forth below, the Commission should require PG&E to provide greater justification on the level of capacity to be retained by demonstrating the risks it describes in its Advice Letter based upon historical experience of those risks being realized. The Commission should also place limits, including firm monthly caps, on the amount of capacity retained so that all LSEs can meet their compliance obligations and the resources are made available through a CAISO must offer obligation.

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1 References to "General Rules" are to the general rules identified in General Order 96-B.

2 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

PROTEST

1. PG&E's Methodology For its Reservation of RA Capacity is Not Sufficiently Justified

D.21-05-030 requires each investor-owned utility (IOU) to file an advice letter to justify its methodology for determining how much of its PCIA -eligible RA is reserved as part of the IOU's BPP. This approach is appropriately tailored to address the transparency concerns raised by Working Group 3 (WG3) co-chairs while minimizing the risk of unintended consequences.[3]

In the Advice Letter, PG&E fails to provide meaningful insight into its methodology for determining how much excess RA capacity PG&E will retain for its own use instead of making the RA available to the market. Rather, PG&E refers to circumstances that would create a desire for PG&E to do so that primarily hinge on uncertainty, compliance, or financial risk. However, a simple listing of potential reasons to retain capacity from a very constrained market is insufficient justification. Based upon the language provided, it appears that PG&E could retain anywhere from 0 megawatts (MW) to all excess MWs in their portfolio to mitigate any of the uncertainty, compliance, or financial risks.

In July 2021 (a high load month), the IOUs collectively retained 619 MWs of RA capacity. This is sufficient to serve a load of 538 MW with the required 115 percent Planning Reserve Margin (PRM). In August, that total retained capacity was 157 MWs which would serve a 136 MW load with the required 115 percent.[4] These are not insignificant amounts and could have served significant amounts of load for smaller load-serving entities (LSEs). Instead, those LSEs themselves faced the uncertainty, compliance, and financial risks that the IOU seeks to avoid. Retaining capacity of this magnitude accordingly deserves more justification than a simple listing of elements that may cause the need to retain.

In addition, the Commission should be working with the California Independent System Operator (CAISO) to determine if the Resource Adequacy Availability Incentive Mechanism (a financial risk) can be replaced with another mechanism to alleviate one of the forms of risk listed by PG&E in this Advice Letter. Doing so could reduce the need to retain capacity allowing all LSEs to meet their compliance obligations. Failing to do so means having MWs in an IOU portfolio that are not subject to a CAISO must offer to ensure that they are available to serve market reliability needs.

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[3] D.21-05-030 at 44.

[4] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

2. PG&E's Proposed Methodology to Retain RA Capacity Does Not Mitigate Unintended Consequences

D.20-05-030 dismissed the WG3 proposal for addressing excess resources on the grounds that:

> This proposal is not properly tailored to minimize the risks that the allocations would create market inefficiencies for RA, raise costs for bundled and unbundled customers alike, or create RA planning and compliance problems when layered with the new CPE and RA compliance requirements.[5]

While the Commission raised concerns with the WG3 proposal and identified unintended consequences, PG&E's retention strategy will have unintended consequences of its own. Any MW in excess of a requirement may never be used for RA (either as substitution or to provide capacity to the CAISO via the Capacity Procurement Mechanism). This will result in a resource not being subject to the CAISO's must-offer obligations, which includes bid insertion if an RA resource fails to offer their energy to the CAISO's markets. Such idle capacity could have been used by an LSE in need of RA and would have been subject to the CAISO's must-offer obligation, ensuring that the energy associated with the capacity is available to reliably serve the market's needs.

3. The Constrained Capacity Market in California Coupled with Significantly Increased RA Penalties is Not a Market in Which Retaining Should be Allowed

With three Commission orders to perform incremental procurement and a proceeding contemplating the acceleration of that procurement to earlier implementation,[6] the strain on availability of capacity is already well documented. During such a constrained capacity environment, the demand for capacity resources can be expected to be high. With RA penalties for the summer of $8.88/kW-month and that penalty amount doubling or tripling dependent on the number of non-compliance events an LSE has had, it is difficult to understand why an LSE should be subject to such penalties while capacity is withheld by the IOUs.

CONCLUSION

For the reasons set forth above, the Commission should require PG&E to provide greater justification on the level of capacity to be retained by demonstrating the risks it describes in its Advice Letter based upon historical experience of those risks being realized. The Commission should also place limits, including firm monthly caps, on the amount of capacity retained so that

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[5] D.21-05-030 at 44.

[6] D.19-11-016 requires 3.3 gigawatts (GW) between the summer of 2021 – 2023, D.21-03-056 requires 1 GW for the summer of 2021, D.21-06-035 requires 11.5 GW between 2023 – 2026, and Rulemaking (R.) 20-11-003 is contemplating accelerating up to 5 GW of procurement from the latter years to the summer of 2022-2023.

all LSEs can meet their compliance obligations and the resources are made available through a CAISO must-offer obligation.

CalCCA thanks the Energy Division for its review of this protest.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl

General Counsel and Director of Policy

cc via email:
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Service Lists: R.17-06-026 and R.19-11-009

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION OPENING BRIEF

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September 20, 2021

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- Existing procurement already performed by load-serving entities (LSEs) to meet future needs that will come online by 2022 or 2023 must be counted toward procurement targets adopted in this proceeding to avoid penalizing early action;
- Because accelerated procurement of up to an additional 5,000 megawatt (MW) by summer 2022 may not be possible -- despite LSEs' best efforts -- the Commission should not introduce new penalties on LSEs for delays to Decision (D.) 19-11-006 procurement outside of their control;
- Given the limited supply of resources, penalties will be inevitable for at least some LSEs. Therefore, if the Commission adopts penalties for failure to accelerate procurement, then the Commission should direct centralized procurement through the investor-owned utilities (IOUs) to avoid unnecessary costs for customers and market disruption;
- The Commission must clarify the modified Cost Allocation Mechanism (CAM) for procurement mandated in D.21-03-056 and must also do so if the Commission adopts a procurement mechanism in which the IOUs procure on behalf of all benefiting customers within this phase of the proceeding;
- The Commission should not modify Resource Adequacy (RA) penalties for LSEs taking reasonable actions to meet RA requirements given the significant increase in penalties only recently adopted in D.21-07-014. Instead, the Commission should maintain existing penalties and adopt a system RA waiver for LSEs who demonstrate reasonable efforts to procure;
- The Commission should establish a process for obtaining more deliverable imports in excess of RA showings by revisiting existing RA import rules and authorizing procurement of deliverable imports up to the available Maximum Import Capability rights (MIC) left over after RA showings;
- The Commission should make the compliance with requirements for incremental procurement tradeable among LSEs to enable more efficient and cost-effective options to meet reliability needs by all LSEs; and
- The Commission should develop a more careful needs assessment to inform procurement needs and RA requirements to minimize the need for future emergency actions.

CalCCA's demand-side recommendations include:

- The Commission should not adopt an auto-enrollment program model for DR programs.

BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	R.20-11-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
OPENING BRIEF

Pursuant to Rule 13.12 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, and the schedule set forth in the *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2*, dated August 10, 2021, the California Community Choice Association[1] (CalCCA) submits this concurrent opening brief.

I. INTRODUCTION

On July 30, 2021, Governor Gavin Newsom signed an emergency proclamation ordering all energy agencies, including the Commission, to work with LSEs on "accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day." The proclamation also directs the Commission to expand and expedite approvals

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

of demand response programs and other clean energy projects to reduce strain on energy infrastructure.[2]

The Commission commenced Phase 2 of this proceeding to examine ways to increase peak and net peak supply resources and reduce peak and net peak demand in 2022 and 2023.[3] The Commission's Energy Division (ED) provided a set of proposals focused on demand reduction, smart thermostats, and utility scale storage, imports, and generation.[4] CalCCA's Opening Brief focuses on supply-side solutions that can be expedited to meet these near-term needs and responds to an ED demand-side proposal on automatic customer enrollment into the Emergency Load Reduction Program (ELRP). In summary, CalCCA's supply-side recommendations include:

- The Commission should encourage expedited procurement of resources available at net peak to a level equivalent to a 17.5 percent planning reserve margin in the summer months of 2022 and 2023;
- Existing procurement already performed by load-serving entities to meet future needs that will come online by 2022 or 2023 must be counted toward procurement targets adopted in this proceeding to avoid penalizing early action;
- Because accelerated procurement of up to an additional 5,000 MW by summer 2022 may not be possible -- despite LSEs' best efforts -- the Commission should not introduce new penalties on LSEs for delays to D.19-11-006 procurement outside of their control;
- Given the limited supply of resources, penalties will be inevitable for at least some LSEs. Therefore, if the Commission adopts penalties for failure to accelerate procurement, then the Commission should direct centralized procurement through the IOUs to avoid unnecessary costs for customers and market disruption;

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2 Proclamation of a State of Emergency: https://www.gov.ca.gov/wpcontent/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.

3 *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2*, Aug. 10, 2021 (Phase 2 Ruling).

4 *Energy Division Staff Concept Paper: Proposals for Summer 2022 and 2023 Reliability Enhancements*, Aug. 16, 2021 (Staff Concept Paper).

- The Commission must clarify the modified CAM for procurement mandated in D.21-03-056 and must also do so if the Commission adopts a procurement mechanism in which the IOUs procure on behalf of all benefiting customers within this phase of the proceeding;
- The Commission should not modify RA penalties for LSEs taking reasonable actions to meet RA requirements given the significant increase in penalties only recently adopted in D.21-07-014. Instead, the Commission should maintain existing penalties and adopt a system RA waiver for LSEs who demonstrate reasonable efforts to procure;
- The Commission should establish a process for obtaining more deliverable imports in excess of RA showings by revisiting existing RA import rules and authorizing procurement of deliverable imports up to the available MIC left over after RA showings;
- The Commission should make the compliance with requirements for incremental procurement tradeable among LSEs to enable more efficient and cost-effective options to meet reliability needs by all LSEs; and
- The Commission should develop a more careful needs assessment to inform procurement needs and RA requirements to minimize the need for future emergency actions.

CalCCA's demand-side recommendations include:

- The Commission should not adopt an auto-enrollment program model for DR programs.

These changes will maximize the potential for bringing in new supply and reducing peak and net-peak demand in the California Independent System Operator (CAISO) balancing authority area (BAA) for Summer 2022 and 2023 to meet net peak requirements.

II. SUPPLY-SIDE RECOMMENDATIONS

A. The Commission Should Encourage Expedited Procurement of Resources Available at Net Peak to a Level Equivalent to a 17.5 Percent PRM in the Summer Months of 2022 and 2023

CalCCA supports a "best-efforts" approach to expedite procurement to meet emergency needs for summer 2022 and 2023. Under normal circumstances, a careful and well-vetted analysis, such as a loss of load expectation (LOLE) analysis, and development of proposals through the RA proceeding would inform any Commission-ordered procurement or modifications to RA requirements with sufficient lead time to reasonably allow construction of new resources. However, given the expedited timeframe of this proceeding, CalCCA supports a procurement mechanism in which LSEs make best efforts to procure additional supply to support summer reliability, similar to the procurement authorized in D.21-03-056.[5] This approach is appropriate for emergency procurement given the uncertainty around how much additional supply is available or can be accelerated in such a short timeframe. This standard should apply to all LSEs to procure or expedite their own procurement of resources available to summer 2022 and 2023 needs to maximize the likely expedited procurement and a more diverse range of solutions.

The CAISO submitted two proposals that would increase RA requirements for LSEs in 2022 and 2023. The first of CAISO's proposals recommends the Commission set the system RA requirements to meet demand and the PRM at 8:00 p.m. for June through October, in addition to the current system RA requirement based on the gross monthly peak.[6] The second proposal would increase the PRM from 15 percent to 17.5 percent to account for forced outages and the increased potential for extreme weather events.[7]

CalCCA supports LSEs making best efforts to bring new resources to the BAA equivalent to a 17.5 percent PRM with resources available at net peak, but cautions the Commission against making modifications to RA requirements within this Phase 2 of the

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5 *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022*, March 25, 2021 (D.21-03-056).

6 *Opening Testimony of the California Independent System Operator Corporation*, Section III, Sept. 1, 2021 (CAISO (Billinton)), at 2:7 – 2:16.

7 *Opening Testimony of the California Independent System Operator Corporation*, Section IV, Sept. 1, 2021 (CAISO (Mohammed-Ali)), at 12:3 – 12:5.

proceeding.[8] Given the tightly constrained RA market and short timeframe to bring RA-eligible resources online, carrying the higher procurement needs into the RA program through higher RA requirements could effectively penalize LSEs – most importantly, their customers – for failing to show enough RA resources despite LSEs best efforts. This is because enough new supply will likely not yet be available or circumstances beyond the control of the LSE prevent resources from coming on-line in an expedited manner. These penalties could come in the form of RA penalties administered by the Commission or capacity procurement mechanism costs for individual deficiencies.

RA requirements and associated penalties are important components of the RA program, as they ensure all LSEs procure their share of resources needed to support reliability. However, all penalties, whatever their nature, will ultimately flow through to customers. The Commission has already taken steps to assign appropriate penalties by increasing RA penalties in modifications made through D.21-06-029 and D.20-06-031.[9] Additionally, the availability of new RA capacity in such a short timeframe is unlikely. Therefore, increasing penalties will likely not provide appropriate incentives to procure but rather, penalize LSEs with few options to procure. Increasing customers' electricity costs further without a beneficial result only exacerbates California's already-high rates. The Commission should not adopt new RA requirements but instead encourage LSEs to use best efforts to expedite procurement of resources available at net peak to effectively meet a 17.5 percent PRM without penalizing them if they are unable to do so given the tight timeframe.

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[8] *Reply Testimony of Marie Y. Fontenot on Behalf of California Community Choice Association*, Sept. 10, 2021 (CalCCA Reply Testimony (Fontenot)) at 3:6 – 5:18.

[9] *Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program*, June 25, 2020 (D.20-06-031) at 60-61; *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, June 24, 2021 (D.21-06-029) at 59-60.

Given the timeframe of this effort, it is clear many LSEs will not be capable of adjusting their RA portfolios or existing contracts to account for higher RA requirements on such a narrow timeline. In Opening Testimony, several parties representing developers, including the California Energy Storage Association (CESA),[10] LS Power,[11] and Independent Energy Producers Association (IEP),[12] emphasize that it will be difficult to procure new resources or accelerate existing planned resource build by Summer 2022. Additionally, several parties, including the ED,[13] CESA,[14] and LS Power,[15] proposed ways to count resources ineligible for RA in procurement ordered in this phase of the proceeding given they could provide additional MW more quickly. This indicates new procurement that may result from this phase of the proceeding may not be eligible to count towards the new requirement the CAISO proposes. Therefore, the Commission should direct LSEs to make their best efforts to procure resources that can meet net peak needs at a level equivalent to a 17.5 percent PRM but should not adopt a new RA requirement.

B. Existing Procurement Already Performed by LSEs to Meet Future Needs That Will Come Online by 2022 or 2023 Must be Counted Toward Procurement Targets Adopted in this Proceeding to Avoid Penalizing Early Action

CalCCA and other LSEs have demonstrated that LSEs are taking reliability needs extremely seriously and efforts already underway have expedited procurement to the extent possible above existing procurement mandates to support summer reliability even before these

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10 *Opening Testimony of Jin Noh on Behalf of the California Energy Storage Alliance*, Sept. 1, 2021 (CESA (Noh)), at 9:4-9:16.

11 *Prepared Phase 2 Opening Testimony of Sandeep Arora on Behalf of LS Power Development, LLC,* Sept 1, 2021 (LS Power (Arora)), at 2-4.

12 *Prepared Testimony of Scott Murtishaw on Summer 2022 and 2023 Reliability Enhancements on Behalf of the Independent Energy Producers Association*, Sept. 1, 2021 (IEP (Murtishaw)), at 1:25-2:8.

13 Staff Concept Paper at 22-25.

14 CESA (Noh) at 27:1-29:19.

15 LS Power (Arora) at 5-6.

concerns were raised in this proceeding. As Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) note, ED's recent update on D.19-11-016 progress found that all 25 LSEs demonstrated effort to meet their Tranche 1 obligations, collectively over-procuring for August 1, 2021.[16] Further, in its Opening Testimony, CalCCA provided data on procurement efforts for 2022 and 2023 among CalCCA members that demonstrated a similar trend for 2022 and 2023 procurement.[17] Based on new power purchase agreement (PPA) data provided by its member CCAs, CalCCA estimates that its members will exceed the D.19-11-016 procurement requirements by 208 September Net Qualifying Capacity (NQC) MW in 2022, and 649 September NQC MW in 2023. The data incorporates project delays and cancellations reported by the member CCAs. Table 1 below shows the derivation of these values.

Table 1: CCA Procurement for D.19-11-016 Mandate, by resource type (Sep NQC MW)[18]

	2022	2023
Hybrid Solar + Storage	352	911
Standalone Storage	253	253
Wind	137	142
Solar	61	139
Geothermal	12	12
Total NQC MW (sum of lines above)	814	1457
Total D.19-11-016 Procurement Requirement for CCAs	606	808
CCA Procurement in excess of D.19-11-016 requirement	208	649

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16 *Pacific Gas and Electric Company Emergency Reliability Order Instituting Rulemaking Errata Testimony*, Chapter 9, Sept. 1, 2021 (PG&E Errata Testimony (Clegg, Wyspianski)), at 9-2:3 to 9-2:19; *Direct Testimony of Southern California Edison Company – Phase 2*, Section III.C., Sept. 1, 2021 (SCE Direct Testimony (W. Walsh)), at 77:7-77:12.

17 *Direct Testimony of Lauren Carr, Fred Taylor-Hochberg, and Marie Y. Fontenot on Behalf of California Community Choice Association*, Chapter I, Sept. 1, 2021 (CalCCA Direct Testimony (Carr, Taylor-Hochberg), 3:20-4:3.

18 This table converts nameplate values to NQC values using the September tech factors from the 2021 NQC list, available at http://www.caiso.com/Documents/NetQualifyingCapacityList-2021.xlsx. Storage resources receive their nameplate capacity as NQC, unless they are less than four hours, in which case they are derated by (duration in hours / 4 hours). As a conservative assumption, hybrid resources receive only the battery's capacity as NQC—the associated generating unit is ignored.

These excess amounts should count towards any new procurement requirement, if any. Additionally, if resources CCAs procure to meet the IRP mid-term reliability requirements in D.21-06-035 can be expedited to reach commercial operation prior to summer 2022 and 2023, those should count as well.

C. Because Accelerated Procurement of Up to an Additional 5,000 MW by Summer 2022 May Not Be Possible -- Despite LSE's Best Efforts -- The Commission Should Not Introduce New Penalties on LSEs for Delays to D.19-11-006 Procurement Outside of Their Control

The Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2 (Phase 2 Ruling) cites a summer reliability stack analysis conducted by the California Energy Commission (CEC) that estimates the potential gap between supply and demand under extreme weather conditions of up to 5,000 MW.[19] While CCAs will make their best efforts to expedite procurement mandated in D.19-11-016, it may not be possible to accelerate new resource build to meet targets adopted in this proceeding given the extremely short timeline and barriers outside of the control of the LSE that can create project delays. Therefore, the Commission should not adopt the proposal in the Staff Concept Paper that would apply fixed or capacity-based penalties to LSEs for not bringing resources online in accordance with the timelines in D.19-11-016.[20] Penalties that apply retroactively on contracts already executed do not allow LSEs to consider penalties in their risk assessments when selecting projects under an expedited timeline. The result then is a contract in which due dates and consequences may not match the new penalties adopted and may leave the LSE with few or no options to implement the new generation in a manner that is compliant with new penalty mechanisms. Further, CalCCA agrees with PG&E[21]

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19 Phase 2 Ruling at 2-3.
20 Staff Concept Paper at 21-22.
21 PG&E Errata Testimony (Clegg, Wyspianski), at 9-1:27 to 9-2:2.

and SCE[22] that applying penalties retroactively to procurement already underway or complete could have negative impacts, including the need to amend contracts to account for the new penalty framework. This could result in increased pricing to account for risks outside the LSE's control or risk the development of the project by opening the contract to renegotiation.

Additionally, projects may experience delays that make it infeasible to meet targeted online dates despite LSEs contracting with project developers up to their procurement requirement to achieve commercial operation as expeditiously as possible. While LSEs may execute contracts with project developers with delay provisions, circumstances outside the control of the LSE may impact commercial online dates. These circumstances can include supply-chain problems, transmission interconnection delays, or COVID-19 impacts, among others. CalCCA's opening testimony provides recent examples of delays on projects contracted by LSEs to comply with expedited procurement mandates demonstrate situations outside an LSEs control can impact project schedules despite LSE compliance with procurement mandates.[23] Both PG&E and SDG&E submitted advice letters on July 23, 2021 informing the Commission of delays preventing projects from meeting targeted online dates of August 1, 2021.[24] These projects were contracted and approved to meet procurement obligations under D.19-11-016 and had targeted online dates of August 1, 2021. Both LSEs complied with the procurement requirement set forth in the Decision but did not have direct control over project development and the delays that prohibited commercial operation of the projects by the August

22 SCE Direct Testimony (W. Walsh), at 76:7-77:6.

23 *Direct Testimony of Lauren Carr, Fred Taylor-Hochberg, and Marie Y. Fontenot on Behalf of California Community Choice Association*, Chapter II, Sept. 1, 2021 (CalCCA Direct Testimony (Fontenot)), 8:24-8:12.

24 See PG&E AL Notification Regarding Delay of Projects Approved Under Decision 19-11-016, July 23, 2021, and SDG&E AL Notification Regarding Delay of Projects Approved Pursuant to Decision 19-11-016, July 23, 2021.

1, 2021 deadline. PG&E cites impacts of the COVID-19 pandemic and supply chain disruptions, both impacts outside of their control, for project delays.[25] These recent examples demonstrate that penalties for project delays may not result in projects meeting their target online dates because delays are not driven by the procuring entity. The Commission should not administer penalties to LSEs who took reasonable actions to procure if projects are delayed by actions or circumstances that are not controllable by the LSE as the procuring entity.

Additionally, there is no evidence LSEs are not taking reasonable efforts to procure to the D.19-11-016 requirements or that LSEs will be short on their 2022 or 2023 obligations. Procurement progress documented in section B above demonstrates LSEs are on track to over-procure relative to their D.19-11-016 requirements. For all the reasons stated above, the Commission should not adopt penalties for delays to D.19-11-016 procurement or increase penalties for RA deficiencies.

D. Given the Limited Supply of Resources, Penalties will be Inevitable for at Least Some LSEs. Therefore, if the Commission Adopts Penalties for Failure to Accelerate Procurement, then the Commission Should Direct Centralized Procurement Through the IOUS to Avoid Unnecessary Costs for Customers and Market Disruption

Expedited procurement or any additional procurement (*e.g.*, additional accelerated mandated procurement, increased RA requirements, or an increased PRM) under tight time constraints will place significant pressure on the market to provide those resources. As described in section C above, penalties are unlikely to arrive at the desired outcome and may disrupt procurement already underway or completed. CalCCA strongly recommends the Commission not adopt new penalties in this proceeding. However, if the Commission does implement additional procurement or subject LSEs to penalties within this proceeding, it should do so for

[25] See PG&E AL Notification Regarding Delay of Projects Approved Under Decision 19-11-016, July 23, 2021.

2022 only and reassess them in 2023 once more information about procurement and reliability needs are known.[26]

The Commission must consider the significant impact to the market of having multiple LSEs compete for limited resources or the expedited operation of already procured resources. This impact is likely to increase market prices and will unnecessarily increase costs for customers. The potential to expedite new resource commercial operation will require selection from a limited set of resources. These resources will already be in the interconnection queue, will likely have already begun if not nearly completed siting and licensing, as well as be significantly under way in supplying the necessary assets. Resources not at this advanced stage are unlikely to be able to achieve the dates contemplated within this proceeding. With a large number of LSEs seeking a limited number of resources, solicitations will be complicated as the sellers will be making offers to multiple entities and making decisions at differing times. Under normal solicitations, a resource dropping out of a solicitation is replaced by other offers. In this case, there may not be any other viable offers to complete the solicitation. Such a process will be inefficient in controlling customer costs and may not be effective in procuring the necessary quantity. Therefore, if the Commission determines additional or expedited procurement and penalties are necessary for 2022, then the Commission should consider centralizing procurement for the amount needed in 2022 using the three IOUs with appropriate allocation of costs and benefits through the cost allocation mechanism (CAM). It should then reassess if penalties and centralized procurement are needed in 2023.[27]

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26 CalCCA Direct Testimony (Fontenot), 11:5-11:15.

27 *Id.*, 11:16-11:19.

E. The Commission Must Clarify the Modified CAM for Procurement Mandated in D.21-03-056 and Must Also Do So if the Commission Adopts a Procurement Mechanism in Which the IOUs Procure on Behalf of all Benefiting Customers Within this Phase of the Proceeding

Within D.21-03-056, the Commission adopted a PRM of 17.5 percent applicable to the three IOUs that were to procure on behalf of all customers. In doing so, the Commission determined that for 2021 and 2022, the IOUs should allocate the costs associated with those contracts through CAM but since only the IOUs would have a 17.5 percent PRM for RA, the RA attributes of the contracts would remain with the IOUs. Finally, D.21-03-056 allowed for procurement of contracts with durations that would extend beyond 2022 while the 17.5 percent target would not extend beyond 2022. There is therefore a significant question regarding what should happen to the costs and benefits of those resources beginning in 2023 should any of those contracts continue beyond 2022. The Commission must therefore clarify what will happen to the modified CAM for D.21-03-056 procurement beyond the timeframe contemplated within that decision so that the costs and benefits are fairly allocated and cost shifts do not occur.

If the Commission adopts a procurement mechanism in this Phase 2 similar to that in D.21-03-056, in which the IOUs procure on behalf of all benefiting customers, the Commission must provide limitations on the modified CAM treatment like those used in D.21-03-056 for resources procured for longer than 2022 and 2023. As stated in CalCCA's reply testimony, if the Commission adopts an IOU-only procurement mechanism, CalCCA recommends the modified CAM treatment for these resources during the period of emergency procurement through 2023.[28] Thereafter, the Commission must determine how costs for those resources should be recovered.

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[28] *Reply Testimony of Marie Y. Fontenot on Behalf of California Community Choice Association*, Sept. 10, 2021 (CalCCA Reply Testimony (Fontenot)) at 7:1 – 8:10.

The simple options would be to either make the resource a bundled load asset or to use a traditional CAM where not only the costs are allocated but so are all the benefits. Such clarification would be necessary in this proceeding if the Commission opts for any form of modified CAM treatment for the period of this expedited procurement in 2022 and 2023. In such a case, the Commission should clarify what happens to such costs in 2024 in addition to what will happen to cost allocation of the authorized D.21-03-056 procurement.

F. The Commission Should Not Modify RA Penalties for LSES Taking Reasonable Actions to Meet RA Requirements Given the Significant Increase in Penalties Only Recently Adopted in D.21-07-014. Instead, the Commission Should Maintain Existing Penalties and Adopt a System RA Waiver for LSES who Demonstrate Reasonable Efforts to Procure

The Staff Concept Paper asks parties to consider doubling penalties for LSEs who may be short in meeting their RA requirements in August and September 2022.[29] This proposal is premature given the modifications made to the penalty structure in D.21-06-029 and does not address the root causes of reliability risks. D.20-06-031 raised the penalty price for failures to meet month-ahead system RA obligations in summer months from $6.66/ kilowatt (kW)-month to $8.88/kW-month.[30] The Commission subsequently adopted D.21-06-029, which declined to increase the overall penalty price and instead introduced a tiered penalty structure in which LSEs accrue points for each month of a deficiency.[31] LSEs with one to five points fall into Tier 1 and pay the applicable RA penalty in $/kW-month; LSEs with six to ten points fall into Tier 2 and pay twice the applicable RA penalty; and LSEs with 11 or more points fall into Tier 3 and pay three times the applicable RA penalty. This new tiered structure is effective for the 2022 RA compliance year.

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29 Staff Concept Paper at 22.
30 D.20-06-031 at 60-61.
31 D.21-06-029 at 59-60.

Testimony from CalCCA[32] and other parties including the Public Advocates Office (Cal Advocates),[33] SCE,[34] PG&E,[35] CESA,[36] LS Power,[37] and the Western Power Trading Forum (WPTF)[38] caution against modifying the RA penalty structure in this proceeding. Parties cite several important drivers for their reasoning: (1) recent modifications to the RA penalty structure adopted in D.21-07-014; (2) factors outside resource developers' and LSEs' control that create project delays; (3) increased ratepayer costs of additional penalties; and (4) existing market signals to procure additional supply. Once the new penalty structure is in place, LSEs will already face doubled, or even tripled, penalty prices if they accrue six or more points and the effects of this change has yet to be analyzed. The proposal in the Staff Concept Paper would further penalize LSEs who do not meet their RA requirements by doubling penalties for LSEs short in meeting their RA requirements in August and September 2022. This proposal is premature given the Commission and stakeholders have not yet had the opportunity to assess the impact of the new penalty structure adopted in D.21-06-029.

Further, making RA penalties more punitive when electric supply is already tight will not result in additional RA procurement; this approach will only increase the costs to consumers without a commensurate benefit. RA deficiencies cannot be attributed to inadequate penalties but rather scarce market conditions and regulatory decisions that hinder LSEs' ability to meet their

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32 CalCCA Direct Testimony (Fontenot), 9:15 – 10:19.

33 *Public Advocates Office Prepared Testimony Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021*, Chapter 3, Sept. 1, 2021, (Cal Advocates Prepared Testimony (Navis)) at 3-2:3 - 3-3:9

34 SCE Direct Testimony (W. Walsh), at 78:4-78:14.

35 PG&E Errata Testimony (Clegg, Wyspianski), at 9-3:5 to 9-3:17.

36 CESA (Noh) at 11:11-12:10.

37 LS Power (Arora) at 7-8.

38 *Western Power Trading Forum Phase 2 Opening Testimony*, Sept. 1, 2021 (WPTF Opening Testimony (Klatt)) at 3-4.

system RA obligations. Increasing the RA requirement to 17.5 percent, particularly during the net load peak hours, is highly likely to require not only the procurement of all existing resources but also the build of new resources as well. A penalty for RA will therefore be a penalty for failing to meet the procurement imposed here. As discussed in section II.C, with a limited field of resources that can meet such a need, it is not likely feasible that all LSEs will be able to meet the procurement requirements. A penalty under such circumstances is not ensuring reliability but rather penalizing those that are unable to obtain capacity that could not be provided in the first place. Therefore, the Commission should adopt a system RA waiver process, similar to the one already in place for local RA, for LSEs who demonstrate reasonable efforts to procure system RA. In its opening testimony, SCE suggested that if the Commission increases RA penalties, the Commission should allow LSEs to file waivers demonstrating commercially reasonable efforts to meet RA obligations, including for system resource adequacy, citing market-level scarcity during summer months.[39] CalCCA agrees with SCE that there is merit in a system RA waiver process and supports its adoption independent of new penalties or RA requirements.

Given current RA market tightness, the Commission should adopt a system RA waiver process that follows the same waiver process that exists for local regardless of the Commission's decision on penalties and RA requirements in this phase of the proceeding. This proposal presents little risk, given the Commission would not grant a waiver unless the LSE demonstrated reasonable actions were taken to meet RA obligations. For these reasons, CalCCA proposes a system waiver be a permanent element of the RA program. CalCCA supported this approach in reply testimony and has long advocated for a system RA waiver process similar to the existing local RA waiver process given RA market tightness.[40] A system RA waiver process is necessary

[39] SCE Direct Testimony (W. Walsh), at 78:14 - 78:17.
[40] CalCCA Reply Testimony (Fontenot) at 6:2 – 6:18.

because penalizing LSEs who, despite commercially reasonable efforts, are unable to meet their requirements will not add capacity to the market in the near term. Until the supply margin increases in the RA market, it will remain difficult if not impossible to obtain RA contracts that fulfill obligations at a reasonable price.

G. The Commission Should Establish a Process for Obtaining More Deliverable Imports in Excess of RA Showings by Revisiting Existing RA Import Rules and Authorizing Procurement of Deliverable Imports Up to the Available MIC Left Over After RA Showings

CalCCA encourages the Commission to make imports – the only low-hanging fruit of any sizeable magnitude – a focal point of its efforts to ensure the state is resourced for 2022 and 2023. Contracting with imports up to the available MIC after RA showings is likely one of the few sources of new resources available to meet procurement requirements given the accelerated timeframe of this proceeding. CalCCA's opening testimony recommended two modifications to existing import RA requirements that would apply for imports procured to meet any summer 2022 and 2023 emergency procurement requirements adopted in this proceeding:

- Do not apply the requirement to bid zero dollars or below for year 2022 and 2023; and
- Allow LSEs to meet emergency reliability procurement targets by contracting with imports after the RA showings deadline up to the available unused MIC.[41]

These modifications will maximize LSEs' ability to secure these imports for California in an increasingly constrained market, rather than hoping that economic imports show up in the market when needed.

Given the challenges with building new resources on such an expedited timeframe, the Commission must ensure that its requirements for imports are not overly restrictive – driving the resources to contract in alternative markets. D.20-06-028 requires RA imports to bid at or below

[41] CalCCA Direct Testimony (Fontenot), 5:12-5:18.

zero in the availability assessment hours beginning for RA year 2021.[42] As California continues to face stressed summer grid conditions, so do other regions across the west and this requirement hinders California LSEs' ability to contract with imports for RA. As the Western Electricity Coordinating Council's (WECC) August 2020 Heatwave Event Analysis Report finds, increased demand during summer months across the Western Interconnection has created more competition for available generation.[43] Requirements on RA imports to bid zero dollars during the net peak hours limit the ability for California LSEs to competitively contract with imports given opportunities for imports to contract elsewhere in western regions without such bidding requirements. While this requirement is intended to ensure the imports are supported by a physical resource that will deliver when dispatched, it may reduce the pool of suppliers willing to offer imports to California. Given it may not be possible to expedite new procurement within the timeframe of this proceeding to meet emergency procurement targets, the Commission should limit barriers to contracting with imports by not imposing bidding requirements on imports resources procured to meet orders in this phase of the proceeding.

CalCCA's opening testimony cites to the CAISO's Department of Market Monitoring's (DMM) First Quarter Report on Market Issues and Performance that demonstrates a "dramatic decline" in the quantity of RA import bids in the first quarter of 2021 compared to the first quarter of previous years.[44] Figure 1 below taken from DMM's report shows the quantity and price of RA import bids into the CAISO market through the first quarter of 2021.

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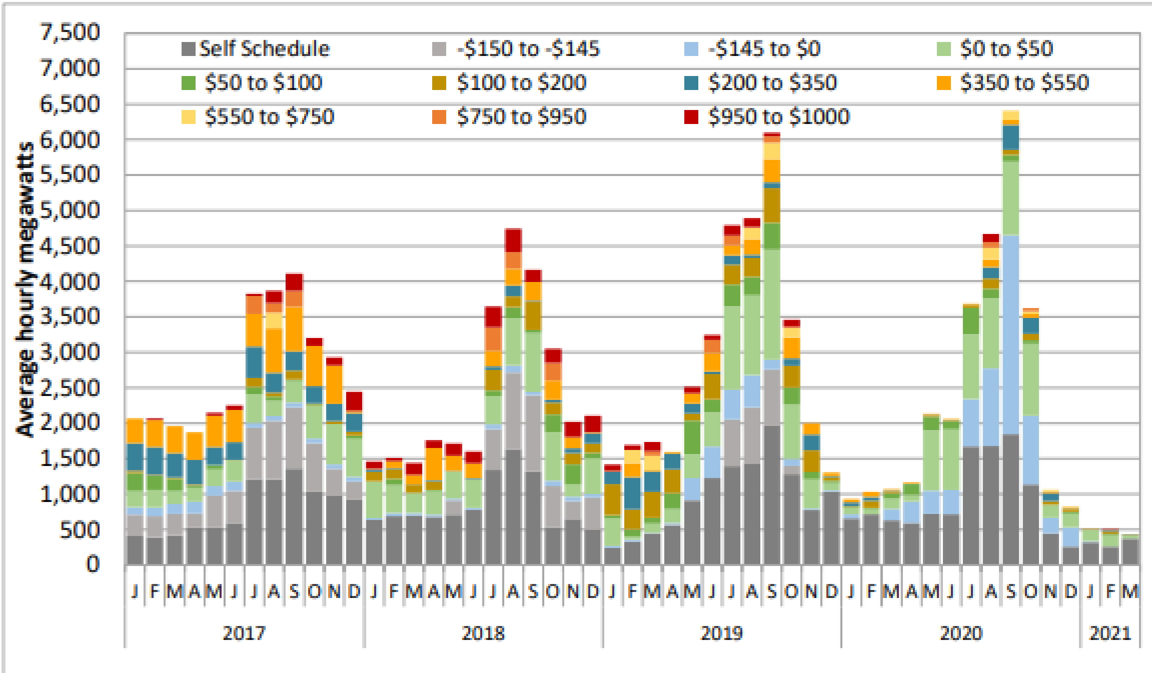
42 *Decision Adopting Resource Adequacy Import Requirements*, June 25, 2020 (D.20-06-028).

43 CalCCA Direct Testimony (Fontenot), 5:20-6:2.

44 *Id.*, 6:9-7:3.

Figure 1: Average Hourly Resource Adequacy Imports by Price Bid



Source: CAISO DMM, First Quarter Report on Market Issues and Performance, June 9, 2021, at 20.

This trend is especially concerning given the emergency conditions California faces in the coming summers. Imports contracted for 2022 and 2023 to meet procurement orders in this proceeding should not be subject to the zero-dollar bidding requirements adopted in D.20-06-028 to allow LSEs to more competitively contract during this time of strained supply.

In addition, the Commission should adopt CalCCA's proposal in opening testimony that would ensure deliverability of imports counting towards emergency procurement targets so those imports procured above those shown for RA can reliably deliver to CAISO load.[45] Including firm imports above MIC limits as eligible resources could result in relying on undeliverable imports to meet emergency procurement targets. CalCCA's proposal would authorize LSEs to procure additional imports *after* RA showings, up to the amount available MIC that was not used for

45 CalCCA Direct Testimony (Fontenot), 7:8-7:15.

monthly RA showings. Doing so would obviate the need for LSEs to procure additional MIC or take MIC from their own portfolio and then determine the value of that MIC, while still ensuring the imports procured are deliverable. By procuring imports after the month-ahead showing process, the amount of MIC not used for RA showings will be known, indicating a high probability that a firm energy import at that location would flow to the CAISO load.

H. The Commission Should Make the Compliance with Requirements for Incremental Procurement Tradeable Among LSEs to Enable More Efficient and Cost-Effective Options to Meet Reliability Needs by All LSEs

The Commission should adopt CalCCA's proposal in opening testimony to make compliance with any procurement requirements adopted in this proceeding tradable among LSEs.[46] When addressing potentially small procurement requirements by multiple LSEs with relatively small loads compared to the total, it is critical that the Commission allow entities to work together to procure resources to meet the total need. The most practical manner to do this is to allow LSEs to trade their compliance with procurement requirements. Allowing such a mechanism will enable LSEs with short positions to sell their compliance credit to an entity with a long position such that the total need of customers can be most effectively procured. Indeed, this best mimics the result in a market with only a few entities procuring resources.

I. The Commission Should Develop a More Careful Needs Assessment to Inform Procurement Needs and RA Requirements to Minimize the Need for Future Emergency Actions

The Phase 2 Ruling cites a summer reliability analysis conducted by the CEC that estimates the potential gap between supply and demand under extreme and average weather conditions.[47] While this stack analysis provides useful information about potential supply conditions under certain assumptions, it falls short of answering the question of how much

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46 CalCCA Direct Testimony (Fontenot), 11:22-12:2.
47 Phase 2 Ruling at 2-3.

additional procurement is needed for summer 2022 and 2023. This analysis projects an additional 600 MW to 5,200 MW of resources may be needed to ensure reliability during the peak and net-peak hours of summer 2022. These figures represent approximately 1 to 11 percent of CAISO peak load in 2020.[48] This large range highlights the limits of stack analyses — it is not clear how to translate this range into a procurement requirement, nor is it clear the level of reliability risk achieved by procuring somewhere within this range.

Subsequently, the CEC issued a Midterm Reliability Analysis & Incremental Efficiency Improvements to Natural Gas Power Plant (Mid-Term Reliability) loss-of-load expectation (LOLE) analysis that examined years 2022-2026 on August 30, 2021. As CalCCA advocated in its opening testimony, a LOLE study should be used to inform procurement needs going forward, rather than stack analyses.[49] An LOLE analysis will more accurately identify the level of reliability achieved by different levels of procurement, informing future procurement decisions. allowing parties to better assess the balance between reliability and affordability. Such analysis can also inform the PRM to ensure the RA program plans for the target level of reliability and informs the level of expenditure of rate payer funds for new procurement needed to meet that target.

CalCCA urges the Commission to prioritize development and consideration of a robust LOLE analysis like the Mid-Term Reliability Analysis to inform future procurement and planning targets. These actions will minimize the need to take emergency actions in the future.

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[48] CalCCA Direct Testimony (Carr, Taylor-Hochberg) at 2:22-2:25.
[49] *Id. at* 3:12-3:19.

III. DEMAND-SIDE RECOMMENDATIONS

A. The Commission Should Not Adopt an Auto-Enrollment Program Model for Demand Response (DR) Programs

The Staff Concept Paper proposes to automatically enroll all residential customers not currently enrolled in a supply-side DR program into the IOU-run ELRP.[50] CalCCA agrees with Marin Clean Energy (MCE) that the Commission should not adopt this proposal.[51] An auto-enrollment design would (1) create a significant market barrier to DR program development, (2) cause increased customer confusion and resulting customer disengagement, (3) have a limiting effect on the potential load reduction impact for certain customer segments, and (4) discriminate against non-IOU DR providers.

CalCCA agrees with MCE that "doubling down" on the ELRP by auto-enrolling all residential customers will not improve the program's effectiveness.[52] Instead, it will diminish each CCA's ability to deploy their own DR programs, which may be more effective or preferred by customers over ELRP. This is especially true because disenrolling customers from IOU programs has proven to be cumbersome and confusing for customers, leaving them unable to participate in alternative programs that may result in superior performance.[53] Instead, the Commission should allow customers to take advantage of alternative programs that may be more effective by not auto-enrolling them in ELRP. This would allow for the continued growth and success of CCA demand flexibility programs.

50 Staff Concept Paper at 5.

51 Marin Clean Energy Prepared Direct Testimony of Alice Havenar-Daughton in Rulemaking 20-11-003, Sept. 1, 2021 (Direct Testimony (Havenar-Daughton)) at 3-2:13 to 3-3:5.

52 Direct Testimony (Havenar-Daughton) at 3-3:13 to 3-3:18.

53 Direct Testimony (Havenar-Daughton) at 3-4:3 to 3-4:14.

IV. CONCLUSION

CalCCA appreciates the opportunity to work with the Commission and parties to maintain summer reliability in the coming years. For the foregoing reasons, the Commission should adopt the recommendations presented in this opening brief:

- The Commission should encourage expedited procurement of resources available at net peak to a level equivalent to a 17.5 percent PRM in the summer months of 2022 and 2023;

- Existing procurement already performed by LSEs to meet future needs that will come online by 2022 or 2023 must be counted toward procurement targets adopted in this proceeding to avoid penalizing early action;

- Because accelerated procurement of up to an additional 5,000 MW by summer 2022 may not be possible -- despite LSEs' best efforts -- the Commission should not introduce new penalties on LSEs for delays to D.19-11-006 procurement outside of their control;

- Given the limited supply of resources, penalties will be inevitable for at least some LSEs. Therefore, if the Commission adopts penalties for failure to accelerate procurement, then the Commission should direct centralized procurement through the IOUs to avoid unnecessary costs for customers and market disruption;

- The Commission must clarify the modified CAM for procurement mandated in D.21-03-056 and must also do so if the Commission adopts a procurement mechanism in which the IOUs procure on behalf of all benefiting customers within this phase of the proceeding;

- The Commission should not modify RA penalties for LSEs taking reasonable actions to meet RA requirements given the significant increase in penalties only recently adopted in D.21-07-014. Instead, the Commission should maintain existing penalties and adopt a system RA waiver for LSEs who demonstrate reasonable efforts to procure;

- The Commission should establish a process for obtaining more deliverable imports in excess of RA showings by revisiting existing RA import rules and authorizing procurement of deliverable imports up to the available minimum indicated volume rights left over after RA showings;

- The Commission should make the compliance with requirements for incremental procurement tradeable among LSEs to enable more efficient and cost-effective options to meet reliability needs by all LSEs;

- The Commission should develop a more careful needs assessment to inform procurement needs and RA requirements to minimize the need for future emergency actions; and

- The Commission should not adopt an auto-enrollment program model for DR programs.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

September 20, 2021

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	Rulemaking 18-07-005 (Filed July 12, 2018)

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION AUTHORIZING PERCENTAGE OF INCOME PAYMENT PLAN PILOT PROGRAMS

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September 22, 2021

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- If the Proposed Decision's eligibility criteria are retained, clarify the time period and number of eligible "recurring disconnections;"

- Specify that the line-item bill credit should be applied to the entire bill by the IOU proportionally to the IOU and CCA charges;

- Revise the IOU and CCA reporting frequency to eight months after the pilot launch and every 12 months thereafter, to allow for more robust data to inform the reports; and

- Require the PIPP working group and evaluator to study and report on mechanisms to include low-income master-metered customers in the PIPP.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	Rulemaking 18-07-005 (Filed July 12, 2018)

**COMMENTS OF
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE PROPOSED DECISION AUTHORIZING PERCENTAGE OF INCOME
PAYMENT PLAN PILOT PROGRAMS**

The California Community Choice Association (CalCCA)[1] submit these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Authorizing Percentage of Income Payment Plan Pilot Programs* (Proposed Decision), issued on September 2, 2021.

I. INTRODUCTION

CalCCA represents the interests of operating community choice aggregators (CCAs) and additional affiliated cities and counties interested in exploring the opportunities of community choice energy. CalCCA's members strongly support this proceeding's aim to reduce the number of households at risk of disconnection for nonpayment of utility bills.[2] The Commission's

1 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, City of San José, Administrator of San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 While disconnections of electric utility service were suspended by the Commission due to the COVID-19 pandemic, and many customers with past due bills may receive arrearage relief through the California Arrearage Payment Program (CAPP) or through payment plans such as the Arrearage

recognition of "the relationship between energy burdens and disconnections" is crucial given the financial burdens inflicted by the COVID pandemic and the fact that disconnections of energy customers were already rising prior to the pandemic.[3] CalCCA supports the Commission's implementation of the Percentage of Income Payment Plan (PIPP) pilot program to test whether such a program can: (1) reduce the number of low-income households at risk of disconnection; (2) encourage participation in energy saving and energy management programs; (3) increase access to essential levels of energy service; and (4) control program costs.[4]

CalCCA supports many aspects of the Proposed Decision and appreciates the Commission's acknowledgment of the benefits of including in the 48-month pilot both investor-owned utilities (IOUs) <u>and</u> CCAs that choose to participate. Not only will qualifying CCA customers be able to obtain the benefits from the PIPP pilot, but the evaluation of the pilot will be considerably more accurate with data from both IOUs and CCAs. In addition, the recovery of electric costs of IOUs and participating CCAs through the Public Purpose Programs Charge (PPPC) is appropriate for this public benefit program.

Management Plan (AMP) program or a COVID Relief Payment Plan, customers unable to qualify (or stay qualified) for these programs could still be subject to disconnection for nonpayment at a future date when the moratorium is lifted. *See Phase I Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-Jurisdictional Energy Utilities,* Decision (D.) 20-06-003 (June 11, 2020) (establishing the AMP); *see also Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* D.21-06-036 (June 24, 2021) (establishing COVID-19 Relief Payment Plans for residential and small business customers and extending the disconnection moratorium to September 30, 2021); *see also* Cal. Govt. Code §16429.5 (establishing the CAPP, and including a provision stating that utility customer service cannot be discontinued for customers with arrearages accrued during the COVID-19 pandemic while the California Department of Community Services and Development (CSD) reviews and approves utility applications for customer arrearage relief).

3 Proposed Decision at 3 ("SB 598 [2017] acknowledged rising disconnections of gas and electric utility customers and the public health impacts of disconnections, especially among vulnerable populations").

4 *Id*. at 2, 12; Conclusion of Law (CoL) 2, at 76.

As set forth below, to ensure the successful implementation and inclusion of CCA customers in the PIPP pilot, CalCCA recommends the following revisions to the Proposed Decision:

- Revise the customer eligibility criteria to include current arrearage/late payment information, rather than recurring disconnections prior to the COVID-19 pandemic, to better reflect changed circumstances as a result of the pandemic;
- If the Proposed Decision's eligibility criteria are retained, clarify the time period and number of eligible "recurring disconnections;"
- Specify that the line-item bill credit should be applied to the entire bill by the IOU proportionally to the IOU and CCA charges;
- Revise the IOU and CCA reporting frequency to eight months after the pilot launch and every 12 months thereafter, to allow for more robust data to inform the reports; and
- Require the PIPP working group and evaluator to study and report on mechanisms to include low-income master-metered customers in the PIPP.

II. THE COMMISSION SHOULD REVISE PIPP PILOT ELIGIBILITY CRITERIA TO REFLECT COVID PANDEMIC CUSTOMER DATA

The Proposed Decision orders that the PIPP pilot will include the following customer eligibility criteria: a customer must either (i) be located in one of the zip codes with the highest rates of recurring disconnections prior to the disconnections moratorium, or (ii) have been disconnected two or more times during the 12 months prior to the disconnections moratorium.[5] CalCCA appreciates the Commission's revision of the Straw Proposal in the Proposed Decision to allow CCAs to designate alternative eligible zip codes from the IOUs. This revision ensures that all CCAs have the ability to participate, given that an IOU's proposed zip codes may be outside of a CCA's territory. As described below, however, CalCCA recommends that the customer eligibility criteria be revised to: (1) include zip codes and customers with high arrearage/late payment statistics instead of high disconnections prior to the pandemic to better

[5] Proposed Decision at 24-25; CoL 7, at 77; Attachment A, §3.a., at 1.

reflect current COVID pandemic economic realities; or (2) in the alternative, clarify the term "recurring disconnections" to ensure standardized application of the criteria.

A. The Customer Eligibility Criteria Should Be Revised to Include Current High Arrearage/Late Payment Information Rather Than Recurring Disconnections Prior to the COVID-19 Pandemic

The Phase 1 Decision in this proceeding, which created the additional rate setting phase to address the PIPP, was issued on June 11, 2020, at a time when the COVID-19 pandemic had only recently begun and the extent of the economic impacts on utility customers was still unknown.[6] The Commission approved Resolution M-4842 on April 16, 2020, suspending disconnections by utilities, which was subsequently extended until June 30, 2021 in Resolution M-4849, and until September 30, 2021 in D.21-06-036. The development of ideas for the PIPP pilot occurred during this time, during which the ALJ requested comments on several sets of questions issued between November 2020 and June 2021. Now, nearly 17 months after the disconnection moratorium was ordered, the Proposed Decision has been issued but still relies on pre-pandemic customer eligibility criteria to determine PIPP pilot participation. The economic landscape of customers has changed dramatically during this time, and the repercussions of the financial challenges caused by the pandemic will be felt for years to come.

CalCCA recommends a revision to the customer eligibility criteria for the PIPP pilot to more accurately identify customers who would most benefit from PIPP enrollment. Rather than disconnections data prior to the pandemic, eligibility should be based on zip codes with the highest rates of, or specific customers with, high arrearages/late payments during the past 12

[6] *Phase I Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-Jurisdictional Energy Utilities,* D.20-06-003 (June 16, 2020).

months.[7] Even when the disconnections moratorium is lifted, high customer arrearages/recurring late payments will continue to reflect customers struggling to retain their utility/CCA service and who are therefore likely in imminent danger of being disconnected by the IOU.

B. If the Commission Retains the Proposed Decision's Current Eligibility Criteria, it Should Clarify the Definition of "Recurring Disconnections"

If, however, the Commission decides to retain the disconnections pilot eligibility, CalCCA requests that it clarify the definition of "recurring disconnections prior to the disconnections moratorium" to ensure standardized application of the criteria. Specifically, the Commission should clarify the time period to measure "recurring disconnections" and how many disconnections during that time period a customer must have to be "recurring."

III. THE LINE-ITEM BILL CREDIT SHOULD BE APPLIED BY THE IOU TO THE ENTIRE BILL

The Proposed Decision requires the IOUs to "provide sufficient data to each participating CCA in weekly reports to facilitate CCA billing of pilot participants"[8] and specifies that "the PIPP bill caps should be implemented as a line-item bill credit."[9] CalCCA appreciates the Commission requiring the IOUs to provide the weekly reports and the proposal to implement the PIPP bill cap as a line-item bill credit. Implementing the bill cap as a bill credit will simplify the implementation of the PIPP. However, the Commission should further specify that the IOU will calculate the bill credit and apply it to the total bill in proportion to the IOU and CCA charges. The monthly bill cap should be allocated in proportion to the split between non-CCA charges and CCA charges because the PIPP bill cap is a cap on a customer's entire bill, not just one portion of it. For example, if a

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7 For example, eligible PIPP customers could be defined as a customer with an arrearage more than 120 days past due, with the arrearage exceeding the product of four times the average IOU/CCA monthly charge.

8 *Id*. at 30; CoL 11.b, at 78.

9 *Id.*, CoL 17, at 81.

customer's bill without the bill cap was $100, $70 for non-CCA charges (e.g., transmission and distribution) and $30 for CCA charges, then the monthly line-item bill credit should be split proportionally to the charges in the bill before the credit is applied (a 70 percent/30 percent split). Furthermore, if the Commission does not specify that the IOU is to calculate and apply the bill credit to the total bill, CCAs will need information about an unbundled customer's complete bill and income level to calculate the portion of the PIPP bill credit that should be applied to CCA charges. A CCA currently has no visibility into the transmission and distribution billing determinants or applicable tariffs. Thus, they cannot calculate an unbundled customer's applicable bill credit.

Additionally, the Commission should require that data to be provided to CCAs should be in the same form as the AMP weekly reports. The specific minimum information in the weekly reports, should include the following:

- enrollment status;
- account identifiers (service agreement, account numbers);
- enrollment start date;
- last bill and payment dates;
- amount to be recovered by the CCA (i.e., the monthly usage times otherwise applicable rate minus the monthly bill cap); and
- the count of missed payments.

IV. THE COMMISSION SHOULD REVISE THE FREQUENCY OF REPORTING REQUIREMENTS TO EIGHT MONTHS AFTER THE START OF THE PILOT AND EVERY TWELVE MONTHS THEREAFTER TO OBTAIN A MORE COMPLETE AND ACCURATE DATA SET

The Proposed Decision requires "[e]ach utility and participating CCA [to] file and serve a report with evaluation metrics covering the previous 6 months of pilot data within 7 months after the launch of the pilot and every 6 months thereafter."[10] CalCCA agrees that filing a report soon

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10 Proposed Decision at 36; Ordering Paragraph 5 at 86.

after the launch of the pilot is appropriate, given that the IOUs are required to enroll its target number of participants during the first six months of the pilot. However, CalCCA is concerned that one month between the close of the reporting period and when the report is due will not allow enough time for compiling the report data because of variations in billing windows and possible data transfer lags to CCAs. For example, if the pilot starts on January 1, and each utility and CCA is to report on data through June 30, by July 30 CCAs would likely barely be receiving billing data for some of the participants on the later end of the meter read schedule. CalCCA therefore requests that the first report be due eight months after the launch of the pilot, rather than seven months.

Additionally, CalCCA requests that instead of requiring reports every six months thereafter, that the Commission require reports every 12 months thereafter. Reducing the number of reports will not only allow for more meaningful reports with the benefit of 12 full months of data but will also reduce administrative costs for the IOUs and CCAs.

V. THE WORKING GROUP SHOULD STUDY, AND THE EVALUATOR SHOULD REPORT ON, HOW TO INCLUDE MASTER-METERED CUSTOMERS IN THE PIPP

The PIPP working group will evaluate the pilot and provide input on long-term planning design.[11] The evaluator will also review the data provided by the working group and the PIPP pilot participants to provide an evaluation report.[12] Along with the many issues listed in the Proposed Decision, CalCCA requests that both the working group and evaluator consider how to include tenants of master-metered buildings in the PIPP.[13] Section 8 housing benefit recipients,

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[11] *Id*. at 65; CoL 29, at 83.
[12] *Id*. at 68-70; CoL 30, at 84-85.
[13] The Proposed Decision excludes master-metered operators and their sub-metered tenants from the PIPP pilot, due to the IOUs only being able to provide a PIPP to individuals who are directly billed by the utility. Proposed Decision at 25.

who are low-income and potential PIPP eligible customers, are often in master-metered buildings. Excluding these customers from eligibility is not consistent with the goals of the PIPP program, and mechanisms to allow their participation should be studied and reported on.

VI. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the Proposed Decision as provided in Exhibit A.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

September 22, 2021

EXHIBIT A

Proposed Changes to Findings of Fact, Conclusions of Law and Ordering Paragraphs

FINDINGS OF FACT

13. The following eligibility criteria may be good indicators that a customer is likely to be at risk of recurring disconnections: (1) residing in one of the zip codes with the highest rate of ~~recurring disconnections~~ customers with high arrearages/late payments during the past 12 months in a utility's or participating CCA's service territory, or (b) having ~~experienced two or more disconnections~~ high arrearages/late payments during the last 12 months ~~prior to the disconnections moratorium~~. High arrearages/late payments include those arrearages that are more than 120 days past due, with the arrearage exceeding the product of four times the average IOU/CCA monthly charge.

CONCLUSIONS OF LAW

7. It is reasonable to limit PIPP pilot eligibility to customers who either (i) are located in one of the zip codes with the highest rates of ~~recurring disconnections prior to the disconnections moratorium~~ customers with high arrearages/late payments during the past 12 months, or (ii) have ~~been disconnected 2 or more times during the~~ high arrearages/late payments during the last 12 months~~prior to the disconnections moratorium~~. High arrearages/late payments include those arrearages that are more than 120 days past due, with the arrearage exceeding the product of four times the average IOU/CCA monthly charge.

11.

b. If a CCA in its service territory opts to participate, the utility will administer pilot enrollment, income verification, and billing, including the application of the bill credit to the total bill in proportion to the IOU and CCA charges. The utility will provide sufficient data to each participating CCA in weekly reports to communicate customer enrollment status ~~facilitate CCA billing of pilot participants~~.

c. CCAs who opt to participate in a utility's PIPP pilot must (i) notify the utility (with a copy to the service list of this proceeding) within 30 days of the effective date of this decision, (ii) participate in the PIPP working group, and (iii) jointly file with the applicable utility a Tier 3 advice letter within 120 days of the final decision to propose a target enrollment level, eligible ~~high disconnection~~zip codes, a marketing, education and outreach plan, and a proposed budget.

e. CCAs may propose eligible ~~high recurring disconnection rate~~ zip codes within the CCA's service territory regardless of whether the utility proposes the same ~~high disconnection rate~~zip codes.

13.

f. Each utility and participating CCA will file and serve a report with evaluation metrics covering the previous 6 months of pilot data within ~~7~~8 months after the launch of the pilot and every ~~6~~ 12 months thereafter. If there is any significant shortfall in enrollments below target enrollment levels, the utility or CCA will explain the shortfall and the plan to remedy the shortfall.

17. The PIPP bill caps should be implemented as a line-item bill credit, and the bill credits should be either (a) the difference between the bill cap and the actual bill, or (b) zero if the actual bill is lower than the bill cap. With respect to CCA charges, the IOU will calculate the bill credit and apply it to the total bill in proportion to the IOU and CCA charges.

26.

a. Contract with community-based organizations that serve eligible ~~high disconnection rate~~zip codes and currently conduct outreach for ESAP and/or LIHEAP to conduct outreach, intake and enrollment for the pilots (and, if they currently conduct income verification for ESAP, to also conduct income verification at enrollment for the pilots);

h. Offer all eligible customers the opportunity to enroll in the pilot program, including by an informational communication that directs customers to the designated community-based organization to receive more information. The communication should be available in languages appropriate for eligible ~~high disconnection rate~~zip codes, as identified by the utility or participating CCA, the contractor community-based organizations, or the PIPP working group.

28.

a. Utilities and participating CCAs may recover electric costs through the Public Purpose Programs Charge, without setting a precedent for potential program expansion.

29.

a. The PIPP working group will advise on CCA implementation, identification of eligible ~~high recurring disconnection rate~~zip codes, outreach, pilot implementation, the evaluation plan, and the long-term program design, including funding sources for the program. The PIPP working group will also study whether the long-term program design can incorporate tenants of master-metered buildings in the PIPP.

30.

o. Is it possible to include tenants of master-metered buildings in the PIPP?

p. If so, how should the PIPP be modified to include tenants of master-metered buildings.

ORDERING PARAGRAPHS

5. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, Southern California Gas Company, and each participating Community Choice Aggregator shall file and serve to the service list of this proceeding a report with evaluation metrics covering the previous six months of pilot data within eight ~~seven~~ months after the launch of the pilot and every twelve ~~six~~ months thereafter. If there is any significant shortfall in enrollments below target enrollment levels, the utility or Community Choice Aggregator shall explain the shortfall and the plan to remedy the shortfall.

9. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company shall each recover electric pilot costs through the Public Purpose Programs Charge and shall recover gas pilot costs from all gas customers in transportation rates on an equal-cents-per-therm basis. If a Community Choice Aggregator in a utility's service territory opts to participate in the PIPP, the utility shall propose a Community Choice Aggregator cost recovery proposal consistent with the Arrearage Management Plan Resolution E-5114 in its PIPP Advice Letter.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS IN RESPONSE TO E-MAIL RULING REQUESTING COMMENTS ON MARKET PRICE BENCHMARK ISSUE DATE

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On behalf of
California Community Choice Association

September 22, 2021

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS IN RESPONSE TO E-MAIL RULING REQUESTING COMMENTS ON MARKET PRICE BENCHMARK ISSUE DATE

The California Community Choice Association[1] ("CalCCA") submits the following comments in reply to parties' responses to the questions posed in Administrative Law Judge ("ALJ") Wang's August 25, 2021 E-mail Ruling ("Ruling") in the above-captioned proceeding.[2] The questions address further analysis from Energy Division Staff's ("ED") May 20, 2021 proposal to revise the publication date for the Power Charge Indifference Adjustment ("PCIA") Market Price Benchmarks ("MPBs") from November 1 to October 1 of each year ("Staff Proposal").[3]

CalCCA agrees with ED that "[t]he November Update is a compressed timeframe conceived when the ERRA proceeding was far less complex – never intended for the depth and

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1 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy Authority, Sonoma Clean Power Authority, and Valley Clean Energy.

2 Rulemaking ("R.") 17-06-026, *E-mail Ruling Requesting Comments On Market Price Benchmark Issue Date* (August 25, 2021).

3 R.17-06-026, Energy Division Staff, *Revision of the Power Cost Indifference Adjustment Market Price Benchmarks Calculation Date from November 1 to October 1 of each year* (May 20, 2021) ("Staff Proposal").

complexity of the data and calculations of the modern PCIA."[4] As such, CalCCA welcomes changes to the November Update that serve to increase transparency and accuracy, and thereby fulfill the purpose of the ERRA update process.

CalCCA supports ED's proposal to move the ERRA update to October 1, provided the remaining procedural schedule, including the ERRA Application date, is also moved forward. Similarly, CalCCA supports Pacific Gas and Electric Company's ("PG&E") proposal to permit flexibility in the timing of the gas and electric forward price curve used in its production cost forecasting, provided a date certain is established in advance.

However, CalCCA urges the Commission to reject PG&E and Southern California Edison Company's ("SCE") proposals to change the basic inputs into the Brown Power MPB, which would constitute a major change to the structure of the PCIA and requires analysis and a process for review and consideration of its impacts. CalCCA also urges the Commission to reject PG&E's proposal to update the PCIA rates in its annual electric true-up ("AET") process, as opposed to relying on the PCIA rates from its approved ERRA forecast. This would, in effect, constitute a "December Update," and thus would require the procedural safeguards and reviews that apply to the current, already time-compressed November update.

I. CALCCA SUPPORTS ED'S PROPOSAL TO MOVE THE ERRA UPDATE TO OCTOBER 1, PROVIDED THE REMAINING PROCEDURAL SCHEDULE IS ALSO MOVED FORWARD.

CalCCA has throughout this proceeding emphasized that ED's proposal to move the update forward by one month will seriously impact the already truncated, pre-update process in

[4] California Public Utilities *Commission Energy Division Workshop on the PCIA Market Price Benchmark Release Date* (June 4, 2021) at 6.

the ERRA proceedings, unless the IOUs' ERRA Application dates are also moved forward.[5] CalCCA has also previously listed the important policy considerations addressed in recent ERRA proceedings, and the importance of the ERRA procedure and review process to all ratepayers.[6] That attention and review has resulted in the identification of hundreds of millions of dollars' worth of errors and unfair methodologies for calculating PCIA rates. The reviews necessary to ensure just and reasonable rates in these over-burdened proceedings are anything but "formulaic and mechanical" as the IOUs prefer to claim.[7]

Because the ERRA applications require a thorough examination during an already truncated period, the loss of a month of pre-update litigation will undermine parties' ability to address these issues and, in turn, diminish the adequacy of the record upon which the Commission relies to address them. Thus, CalCCA reiterates that this process would be irreparably harmed if the forecast update is moved to October 1, unless the original application date and the remaining procedural schedule is also moved up commensurately.

II. PROPOSALS FOR A LOAD WEIGHTED ENERGY INDEX CALCULATION IN THE BROWN POWER MPB REQUIRE AND DESERVE FURTHER ANALYSIS.

While CalCCA appreciates the efforts of the IOUs to increase accuracy in ERRA forecasting, the proposed change in the MPB calculation is not appropriate at this time. SCE and PG&E claim that changing to a load-weighted energy index calculation can mitigate the "lack of

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5 R.17-06-026, *California Community Choice Association's Comments in Response to Staff's ERRA Timing Proposal* (June 15, 2021) ("CalCCA June 15 Comments") at 6; R.17-06-026, *California Community Choice Association's Comments in Response to E-Mail Ruling Requesting Comments on Market Price Benchmark Issue Date* (September 13, 2021) ("CalCCA September 13 Comments") at 10.

6 CalCCA June 15 Comments at 8-9; CalCCA September 13 Comments at 11-12.

7 R.17-06-026, *Joint Opening Comments of Southern California Edison Company (U 338 E) and Pacific Gas and Electric Company (U 39 E) on the Energy Division Staff Proposal Concerning the Timing Of The Market Price Benchmarks* (June 15, 2021) at 1-2, n. 2.

accuracy" in the MPB resulting from ED's proposal to move the issue date forward.[8] However, neither utility has provided any numerical analysis demonstrating the ultimate impact of their proposals on PCIA rates, *i.e.*, the same shortcoming for which SCE and San Diego Gas & Electric Company ("SDG&E") criticize ED's proposal in their opening comments.[9]

The change proposed by the IOUs, while potentially beneficial to all customers, deserves significant analysis and consideration. This important structural change in the calculation of the PCIA would eliminate transparency into a major PCIA component and thereby increase uncertainty. This potential cause of "rate shock" should not be adopted based on unsubstantiated comments made in response to the ALJ's ruling. This issue belongs in a later phase in this or another proceeding.

A. The impact of PG&E and SCE's Load-Weighting Proposals on the MPB is More Uncertain than ED's Proposal to Shift the MPB calculation from October to September.

PG&E bases its proposal for a load-weighted energy index calculation on the claim that "utilization of each IOU's respective PCIA supply portfolios when determining a monthly on peak/off peak weightings, rather than customer load, will improve the precision of the forecasted brown power index. . . . Such methodological improvement would be helpful to mitigate any increased forecasting inaccuracy caused by an energy MPB date change."[10] Similarly, SCE

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8 R.17-06-026, *Opening Comments of Pacific Gas and Electric Company (U 39 E) on Market Price Benchmark Issue Date* (September 13, 2021) ("PG&E Opening Comments") at 5; R.17-06-026, *Response of Southern California Edison Company (U 38 E) to Administrative Law Judge's Ruling Requesting Comments on the Market Price Benchmark Issue Date* (September 13, 2021) ("SCE's Opening Comments") at 2.

9 SCE Opening Comments at 3-4; R.17-06-026, *San Diego Gas & Electric Company (U 902 E) Comments on Ruling Regarding Market Price Benchmark Issue Date* (September 13, 2021) at 2-3.

10 PG&E Opening Comments at 5.

proposes that "The forecast Energy Index MPB should be calculated based on the investor-owned electric utility's (IOU's) generation profile shapes, not its customer load shapes."[11]

> Making this straightforward but important structural change in the Energy Index MPB will go a long way to counterbalancing the potential degradation to forecast accuracy the proposed change from October to September will introduce . . . .[12]

ED's original analysis is based on some assumptions regarding the decrease in accuracy that may result from moving the issue date farther from the date to be forecast.[13] However, even making such assumptions, ED's analysis concludes there would be minimal impact to the PCIA from making this change.[14] In fact, PG&E agrees that "by using September forwards instead of October forwards, forecasting accuracy will diminish by a limited amount as a result of the timing change."[15]

Nonetheless, both IOUs claim the change they propose will help mitigate the "degradation in accuracy" caused by moving the MPB issue date to October. Neither IOU provides any support or analysis regarding the scope or impact of this "degradation" in accuracy. Likewise, neither have come forward either with data or analysis to support the claim that a change to the energy index calculation would mitigate this perceived issue.

CalCCA agrees with SCE in not supporting changes to the PCIA unless such changes are sufficiently justified.[16] Thus, CalCCA strongly urges the Commission to consider any proposed changes to the energy index to a phase, or proceeding, where more analysis can be performed and a full record established.

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11 SCE Opening Comments at 8-9.

12 *Id*. at 2.

13 *See Energy Division Staff Analysis of Changes to Market Price Benchmarks Resulting from the Staff Proposal in R.17-06-026* (attached to Email Ruling August 25, 2021) at 8.

14 *Ibid*.

15 PG&E Opening Comments at 3.

16 SCE Opening Comments at 4.

B. PG&E and SCE's Proposals Would Eliminate Transparency in the MPB Calculation and Unnecessarily Confuse MPB implementation.

One of the benefits of the current energy index calculation is its transparency. If, instead, the current calculation is replaced by each utility's forecast of wholesale market revenue based on its own production cost modeling, this benefit will be lost. Stakeholders will not have access to the data driving the ultimate calculation until the final calculation is presented to them, removing any ability to plan for changes to the PCIA.

In addition, because each utility may prepare its forecast using different inputs, and different production cost models, each IOU will presumably apply different price curves, and use different timelines for running its models. Instead of a uniform method for determining the relevant MPB, each IOU would in effect create its own methodology. As a result, all reviewers, including Staff, will need more time, not less, to review the process undertaken and the resultant PCIA calculations. Whatever decrease in "accuracy" Staff's proposed change of the MPB issue date may incur does not outweigh the complexities and lack of transparency that would result from PG&E and SCE's proposal.

C. PG&E and SCE's Proposals Are Out of Scope and Deserve Consideration in a Later Phase.

Although presented as such by PG&E and SCE, the IOUs' proposals to revise the method for establishing the "energy index" MPB are not a simple change to the benchmark's calculation methodology. The proposals, if adopted, would constitute a major change such that the "Brown Power Index" of the MPB would no longer even be an "index" benchmark at all. These proposals go far beyond commenting on the issuance date or calculation date of the MPB, and are thus out of the scope of comments requested by ALJ Wang's Ruling.

To support its proposal to change the MPB inputs by one month (which would be trued up, in any case, but for the "lost" September data for balance-of-year transactions in the forecast

MPB calculation), ED conducted data analysis and presented its findings through workshops and this opportunity to comment. By contrast, SCE and PG&E propose a major change to the Brown Power benchmark calculation, and recommend the Commission accept this proposal without further analysis or comment. The PCIA was litigated over three years, including detailed analysis and discussion of each component of the MPB. The proposed changes to the design of the Brown Power benchmark should not be made via comments in response to this Ruling. Any such change should be adopted only with significant analysis of its impact on the resultant PCIA calculation, and stakeholders' opportunity to review and consider its implications.

III. CALCCA SUPPORTS PG&E'S PROPOSAL TO ADD FLEXIBILITY TO THE FORWARD PRICE CURVES USED IN FORECASTING, PROVIDED A DATE CERTAIN IS SET IN ADVANCE.

PG&E proposes that if the November Update date is moved to October, it be allowed "increased flexibility in selecting forward curve dates to produce PG&E's Prepared Testimony and Testimony Update"[17] so that market data on gas and electric forward prices may be calculated no greater than 45 days prior to the filing date.[18] CalCCA supports PG&E's ability to perform modelling closer to the actual day of filing testimony.

However, to ensure certainty in the process and avoid any potential gamesmanship, PG&E should be required to pick a date certain on which the price calculation will take place, balancing the use of a date closer to the submittal of testimony with the time it takes PG&E to run its updated figures. For example, PG&E could set the timing for the forward price curve as "30 days prior to the November Update deadline." Once that day is selected, this day would then be used in proceedings going forward. The Commission would determine whether

[17] PG&E Opening Comments at 7.
[18] *Id*. at 8.

circumstances justify a change to that specified date. This avoids the potential for PG&E to select among different forward price curves (*e.g.*, comparing a curve forecasted 15 days prior to the deadline with a curve that had been forecasted 25 days prior) with an eye towards picking the curve that would result in the PCIA rates more favorable to bundled customers.

IV. A "DECEMBER UPDATE" SHOULD NOT BE ADOPTED.

Suggesting this proposal would mitigate the perceived inaccuracy that would result from the proposed change to the MPB issue date, PG&E proposes to implement rates, including PCIA rates, in its annual electric true-up ("AET") process using its latest available balancing account balances, and not those forecast balances utilized in PG&E's ERRA Forecast update.[19] PG&E claims this approach "would improve ratemaking accuracy and mitigate the accuracy lost through the implementation of an October Update."[20]

However, the risks of this proposal far outweigh any perceived increase in forecast accuracy. Indeed, permitting PG&E to update PCIA rates in its AET using its latest account balances would require a stakeholder and Commission review and approval. This review would have to be performed by Staff and all stakeholders in an even more compressed timeframe than the current status quo the change in the MPB issue date was intended to alleviate. The Commission should reject this proposal for what would, in effect, constitute a "December Update."

The Staff Proposal intends to address current problems encountered by a time-compressed review schedule. PG&E's proposal, however, would result in even less notice to stakeholders and ED staff of the balances subject to the PCIA, and therefore the total effective

19 *Id*. at 9.
20 *Ibid*.

PCIA charge, than there exist currently. With such a decrease in transparency, stakeholders' ability to plan for changes to the PCIA would also be seriously impacted. The already-problematic potential for rate shock that currently exists would be even greater under PG&E's approach.

As CalCCA has also repeatedly stressed, the process for obtaining from PG&E data and information needed to perform the review required in the current ERRA process is difficult. As we detailed extensively in our opening comments, discovery in these cases is time-consuming and frequently disputed.[21] Because there are no formal discovery rights in the advice letter process, stakeholders frequently engage in time-consuming disputes to obtain the information they need from PG&E. Even if such disputes are ultimately successful, the level of effort and amount of time devoted to it is eye-opening.[22]

In addition, and as we have continued to raise, advice letter dockets are not procedurally amenable to resolving fact-based questions that rely on confidential information.[23] There is no formal discovery process, exchange of testimony or evidentiary hearing in an advice letter process. A party's ability to review confidential information depends on the willingness of the IOU to agree to a nondisclosure agreement, and to do so in a timely fashion that enables the reviewing representative sufficient time to perform the review needed.

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21 CalCCA September 13 Comments at 11.

22 For example, understanding the causes of a $590 million undercollection in a recent ERRA compliance case required disputing submission of over 325 discrete discovery questions, a motion to compel (withdrawn after production), three submissions by PG&E of revised or supplemental testimony, and three requests for schedule revisions, the last of which was granted. R.19-06-001, *Opening Comments of the Joint Community Choice Aggregators* (February 13, 2020) at 11-12.

23 A.20-02-009, *Opening Comments of Joint Community Choice Aggregators on Proposed Decision Resolving Phase One of Pacific Gas and Electric Company's Energy Resources Recovery Account (ERRA) Compliance Application for the 2019 Record Year* (June 30, 2021) at 11.

PG&E's proposal would add another step to the process and another update that is subject to error, would require review and, inevitably, would lead to disputes regarding requests for data and further information. PG&E's proposal highlights current impediments to effective discovery and, therefore, review of the matters intended for review under the ERRA process. Approving this proposal would further erode stakeholders' ability to perform an effective review.

V. CONCLUSION.

CalCCA thanks the Commission for the opportunity to file these comments, and respectfully requests the Commission adopt the recommendations herein.

Respectfully submitted,

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On behalf of
California Community Choice Association

September 22, 2021

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING
COMMENTS ON PROPOSED PREFERRED SYSTEM PLAN**

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September 27, 2021

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SUMMARY OF RECOMMENDATIONS

- Confirm that the full 11.5 NQC GW from the MTR Decision is not layered on top of the LSE plans – both (1) the amount of MTR resources added on top of LSE plans; and (2) the procurement within LSE's IRPs should be counted toward the 11.5 NQC GW, by the amount of the excess procurement relative to D.19-11-016 and the amount provided by LSE IRPs.

- Adopt the 38 MMT Core Portfolio as the PSP with the sensitivity of the 22.5 percent "high-need" PRM not persisting past 2026, if the sensitivity, tested in SERVM for the years 2026 through 2030, is reliable;

- Commit that modeling for the next PSP will take into account climate change assumptions, including potential future prolonged low hydro years and the social cost of carbon;

- Commit to lowering the 38 MMT GHG target to 30 MMT in the next PSP;

- Ensure flexibility in the procurement of resources by measuring and encouraging best efforts to meet procurement targets in LSE plans without the imposition of penalties or backstop procurement; and

- Ensure that any new procurement order does not require resource or technology specific procurement requirements.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON PROPOSED PREFERRED SYSTEM PLAN

The California Community Choice Association[1] (CalCCA) submit these Comments in response to the *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan* (ALJ Ruling), issued on August 17, 2021.

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the ALJ Ruling regarding the proposed Preferred System Plan (PSP). As evidenced by the recent accelerated "emergency" procurement orders requiring parties to procure 14,800 megawatts (MW) in response to strained electricity markets,[2] adequate planning and modeling is crucial moving forward to ensure stable

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, City of San José, Administrator of San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *See* D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023,* R.16-02-007 (Nov. 13, 2019) (requiring 3,300 MW of incremental system resource adequacy resources to be procured [by all LSEs], with at least 50 percent online by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023); D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003 (June 30, 2020) (MTR Decision) at 36-38 (requiring 11,500 MW of incremental capacity to be procured by all LSEs).

markets and reliable service for California customers. CalCCA has commented on the lack of robust analysis and modeling associated with these orders.[3] The analysis set forth in the ALJ Ruling and the September 1, 2021 workshop, however, demonstrate robust modeling and analysis, and CalCCA is appreciative of the substantial efforts put forth to ensure an accurate picture of the procurement needs for the next decade.

The comments below respond to the 25 Questions for Parties in the ALJ Ruling in the order that they appear in the ALJ Ruling.[4] While generally supportive of the California Public Utilities Commission's (Commission) individual Integrated Resource Plan (IRP) plan aggregation, and the reliability and green-house gas (GHG) modeling analysis, CalCCA recommends the following:

- Confirm that the full 11.5 NQC GW from the MTR Decision is not layered on top of the LSE plans – both (1) the amount of MTR resources added on top of LSE plans; and (2) the procurement within LSE's IRPs should be counted toward the 11.5 NQC GW, by the amount of the excess procurement relative to D.19-11-016 and the amount provided by LSE IRPs;
- Adopt the 38 MMT Core Portfolio as the PSP with the sensitivity of the 22.5 percent "high-need" Planning Reserve Margin (PRM) not persisting past 2026, if the sensitivity, tested in Strategic Energy Risk Valuation Model (SERVM) for the years 2026 through 2030, is reliable;
- Commit that modeling for the next PSP will take into account climate change assumptions, including potential future prolonged low hydro years and the social cost of carbon;
- Commit to lowering the 38 million metric ton (MMT) GHG target to 30 MMT in the next PSP;

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3 *See, e.g., Comments of California Community Choice Association on the Proposed Decision and Alternate Proposed Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003 (June 10, 2021) at 5 ("the change to the high-need scenario [ordering 11.500 MW instead of 7,500 MW of additional procurement] based on such broad-brushed, high level conclusions, without the rigorous analysis and reliable modeling necessary to pinpoint the requisite procurement amount, runs the risk of significant over-procurement at customers' expense").

4 ALJ Ruling at 50-54.

- Ensure flexibility in the procurement of resources by measuring and encouraging best efforts to meet procurement targets in LSE plans without the imposition of penalties or backstop procurement; and
- Ensure that any new procurement order does not require resource or technology specific procurement requirements.

II. RESPONSE TO QUESTIONS FOR PARTIES IN ALJ RULING

The following provides CalCCA's responses to the 25 questions in the ALJ Ruling.

1. **Please comment on the individual IRP portfolio aggregation performed by Commission staff.**

CalCCA is generally supportive of the Commission's approach aggregating the portfolios of the individual load serving entities (LSEs) filed on September 1, 2020, as described in Section 2 of the ALJ Ruling, "Aggregation of LSE Plans" as well as Attachment A to the ALJ Ruling. Commission staff spent considerable effort checking for errors, as well as correcting and clarifying LSE plans to ensure accurate data.

CalCCA requests clarification on the interaction of resources ordered in the Mid-Term Reliability (MTR) Decision, and the baseline described in the ALJ Ruling, which consists of "an updated baseline of resources that are online and delivering to the California Independent System Operator (CAISO), or are in development with executed and approved contracts."[5] As shown by Table 3 below, CCAs are exceeding their Decision (D.) 19-11-016 requirements in 2022 and 2023. This excess should count towards the 11.5 NQC GW from the MTR order. Additionally at the September 1, 2021 Commission Workshop, Commission Staff presented the Preferred System Plan (PSP) Analysis, where the chosen PSP portfolio did not require the full 11.5 NQC GW in the MTR order when considering LSEs' IRPs. Therefore, CalCCA requests confirmation that the full 11.5 NQC GW from the MTR Decision is <u>not</u> layered on top of the LSE plans —

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[5] *Id.* at 4.

both (1) the amount of MTR resources added on top of LSE plans; and (2) the procurement within LSE's IRPs should be counted toward the 11.5 NQC GW, by the amount of the excess procurement relative to D.19-11-016 and the amount provided by LSE IRPs.

2. Comment on the reliability analysis of the aggregated 38 MMT LSE plans.

CalCCA is appreciative of the Commission's recognition of the diversity of resources in the September 1, 2020 plans of community choice aggregators (CCAs) as compared to those planned by the investor-owned utilities (IOUs) or Electric Service Providers (ESPs).[6] While LSEs were required to submit plans that met their portion of the 46 MMT GHG target by 2030 as set forth in D.20-03-028, as noted by the Commission many CCAs have planned for higher amounts of GHG-free resources, as detailed in Table 1 below:

Table 1: CCA Portfolios filed September 1, 2020

CCA	MMT
Central Coast Community Energy	31
Clean Power San Francisco	24
Desert Community Energy	32
Marin Clean Energy	30
Peninsula Clean Energy Authority	26
Redwood Coast Energy Authority	30
San Diego Community Power	34
Silicon Valley Clean Energy	17
Sonoma Clean Power	29

The CCA plans reflect their commitment to GHG-free resources and renewable energy.

CalCCA requests clarification on Table 1 of the ALJ Ruling ("LOLE Results from Aggregated LSE Plan Portfolios") regarding the substantial 7 TWh/year difference in 2030 annual load figures for the 38 MMT portfolios (258,290,192 megawatt hour (MWh)) versus the 46 MMT portfolios (265,501,285 MWh).[7] In theory, these numbers should be very close to one

6 *Id.* at 8.
7 *Id.* at 10, Table 1.

another (as are, for example, the 2026 results of 255,116,344 MWh (46 MMT) and 255,094,310 MWh (38 MMT)) because the SERVM model is being run for the same year with the same sets of load inputs.

3. **Comment on the appropriateness of the scenarios and sensitivities developed in RESOLVE to be considered as the preferred portfolio. Suggest any alternative sensitivities or changes to the analysis.**

After determining that the aggregated LSE plan portfolios (both the 38 MMT and 46 MMT portfolios) failed to meet GHG and reliability targets due to insufficient new capacity, the Commission utilized Renewable Energy Solutions Model (RESOLVE) to construct scenarios for potential PSP candidates.8 The Commission analyzed several sensitivities in RESOLVE, finding that by 2030 the 38 MMT Core results indicate that the reliability and GHG constraints are met through the aggregated LSE plan resources plus the resources ordered in the MTR Decision, along with 286 MW addition of utility-scale solar that RESOLVE found necessary for the period 2030-2032.[9]

The Commission provided LOLE analysis through SERVM for some of the sensitivities listed in the ALJ Ruling, but not all.[10] Specifically, the Commission did not provide SERVM analysis for the 38 MMT "non persistence" sensitivity in which the "high need" PRM of 22.5 percent adopted in the MTR Order does not persist past 2026 (referred to herein as the "Non-Persistence Sensitivity"). The Non-Persistence Sensitivity is important for comparison to the 38 MMT Core and is consistent with previously established IRP planning assumptions. Although

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8 *Id.* at 12-13.

9 *Id.* at 16.

10 In addition, while CalCCA appreciates the Commission analyzing the many sensitivities as compared to the 38 MMT core, it questions the purpose of such sensitivities other than understanding the context in which it chooses one portfolio over the other. Why one sensitivity must be chosen over another is unclear. The Commission should simply provide justification for the sensitivity it ultimately adopts as the PSP, and why it chose that over the others.

the MTR Order determined that resources *approximating* a 22.5 percent PRM would be needed to replace Diablo Canyon, it would be premature to adopt this as an official PSP target after 2026 because there has been no loss of load expectation (LOLE) analysis demonstrating that necessity. In fact, the 2030 LOLE results demonstrate that the 38 MMT Core (with the 22.5 percent PRM) is substantially *below* the 0.1 LOLE standard (at 0.054 LOLE) in that year, potentially resulting in an overbuilt system.[11]

The Commission should not expressly or implicitly adopt a 22.5 percent PRM for the years after 2026 -- i.e. future LSE plans submitted in IRP should not be forced to conform to a 22.5 percent PRM after 2026 -- absent adequate modeling and planning reserve setting analysis. CalCCA therefore recommends that the Commission re-run RESOLVE with a 17.5 percent PRM for the years 2026-2030. A PRM of 17.5 percent already has support in the record of the Commission's Extreme Weather rulemaking, and is thus a reasonable starting point for an estimate of system need.[12] The portfolio output by RESOLVE can then be tested in SERVM (using similar assumptions as the 38 MMT Core without the Non-Persistence Sensitivity[13]) for the years 2026 and 2030. If the 38 MMT Core with the Non-Persistence Sensitivity portfolio is determined to be reliable (i.e. below 0.1 LOLE), the Commission should adopt it as the PSP, rather than the 38 MMT Core. If the 38 MMT Core with the Non-Persistence Sensitivity portfolio is determined to be not reliable, the Commission should incrementally increase the PRM in years 2026-2030 until the 38 MMT Core with the Non Persistence Sensitivity portfolio is found to be reliable.

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11 *See* ALJ Ruling, Attachment B at 224.

12 See MTR Decision, Ordering ¶ 14, at 82 ("PG&E, SCE, and SDG&E should be directed to continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve this effective 17.5% PRM for the months of concern").

13 *See* ALJ Ruling, Attachment A at 71.

Finally, CalCCA notes that the Commission should only use the PRM output by the analysis described above for IRP planning purposes. Using it to set resource adequacy requirements is out of scope of the current proceeding.

4. Comment on the SERVM analysis and results of the 38 MMT Core Portfolio.

CalCCA is appreciative of the Commission's SERVM analysis for this PSP, and generally supports the adoption of the 38 MMT Core Portfolio (with modifications regarding the Non-Persistence Sensitivity as detailed above in response to question 3). However, CalCCA recommends that any future SERVM analysis take into account climate change, and specifically: (1) potential future prolonged low hydro years; and (2) the social costs of carbon emissions.[14] In addition, consistent with the Commission's recommendation in the MTR Order to lower the GHG target required by D.20-03-028 from 46 MMT to 38 MMT for this PSP,[15] CalCCA recommends that the Commission consider lowering the target in the next cycle to 30 MMT to ensure the progression towards California's 2045 carbon-neutrality goals.

First, the Commission's SERVM analysis fails to take into account future prolonged low hydro years, relying instead on historical hydro conditions. The Modeling Conventions used for the 38 MMT Core Portfolio state that:

> Certain assumptions reflect historical data without projections of future climate change; for example, hydro assumptions based on weather year 1998-2017, which means recent low hydro years since 2018 are not part of the analysis. Current low hydro conditions may recur in future years given climate change, particularly in California, which may exacerbate reliability conditions due to decreased overall

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[14] Cost-optimized energy portfolios must include all costs borne by customers, not just portfolio costs, including the costs of wildfires, drought, heat waves and heat-related outages induced by emissions from the electricity sector. Customers pay both sets of costs, so incorporating only portfolio costs while ignoring externalities will not deliver a portfolio optimized for customers.

[15] *See* MTR Order at 19.

hydro generation. Likewise, other planning assumptions may not fully represent a climate change future.[16]

Given predictions of declining hydropower over time, the Commission should be including in its SERVM analysis at least a derate of hydro capacity to reflect climate change. The SERVM results predict 25,393 gigawatt hours (GWh) of hydro generation in 2026 and 25,394 GWh in 2030 for the CAISO area — reflecting an average value across the 1998-2017 weather years.[17] According to the California Energy Commission, however, 2020 (drought year) hydro production *for the entire state of California* (i.e., a footprint that includes and is larger than CAISO, which only serves about 80 percent of California load)[18] was only 21,414 GWh, which is substantially lower than the SERVM values inputted.[19]

Lower hydro production is likely to continue given the prolonged drought, and thus the CPUC should adjust its historical hydro data going forward. Table 1 below shows drought indices in the west, with darker colors indicating more severe droughts. Since 2021, the dark brown colors indicate that severe drought has increased, in both persistence and magnitude, beyond any level seen since 2000.[20]

Table 2. U.S. Drought Monitor Data

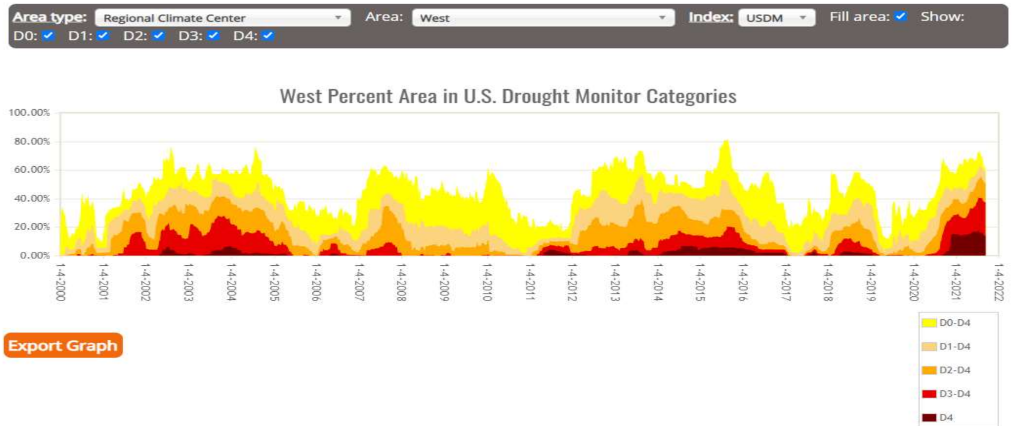
16 ALJ Ruling, Attachment B at 221.

17 *Id.* at 223.

18 *See* Website of the California Independent System Operator, "About Us," ("[t]he ISO manages the flow of electricity across the high-voltage, long-distance power lines for the grid serving 80 percent of California and a small part of Nevada.") http://www.caiso.com/about/Pages/OurBusiness/Default.aspx.

19 California Hydroelectric Statistics and Data, Total Hydro Electricity Production (Annual Totals; Excludes Imports), California Energy Commission, at https://ww2.energy.ca.gov/almanac/renewables_data/hydro/index_cms.php

20 U.S. Drought Monitor, Data, Time Series, https://droughtmonitor.unl.edu/CurrentMap.aspx . D0 is abnormally dry, D1 is a moderate drought, D2 is severe drought, D3 is extreme drought, and D4 is exceptional drought.



In addition, the Commission should in the future incorporate into its modeling the social costs of carbon emissions (i.e., the damage costs to society resulting from climate change). In D.19-05-019, the Commission adopted a three-element Societal Cost Test (SCT) to be tested in the IRP proceeding "initially for information purposes, but ultimately to move forward in ensuring that cost-effectiveness analyses accurately reflect the environmental policies of the Commission and California."[21] In addition, Public Utilities Code section 701.1 requires as a "principal goal" of electric utility resource planning, in addition to other ratepayer protection objectives, to "minimize the cost to society" and to "improve the environment."[22] Given the significant costs associated with carbon emissions, the Commission should conduct and review the results of testing the SCT for consideration in future IRP cycles consistent with D.19-05-019.[23]

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21 D.19-05-019, *Decision Adopting Cost-Effectiveness Analysis Framework Policies For All Distributed Energy Resources,* R.14-10-003 (May 21, 2019) at 29.

22 Cal. Pub. Util. Code §701.1(a)(1).

23 Recent scientific work has also demonstrated the impacts of the mortality costs of carbon above and beyond the social costs of carbon. *See* Besler, D.L., The Mortality Cost of Carbon, *Nature Communications* 12:446 (2021), https://doi.org/10.1038/s41467-021-24487-w. Those costs amount to 2.26 x10^{-4} excess death per ton of carbon emitted through 2100. *Ibid.* At this rate, a change from a target of 38 MMT and 30 MMT would save approximately 1,800 lives through 2100 in 2030 alone. Assuming a linear reduction to 38 MMT in 2030 and then to 15 MMT in 2045 as indicated in the IRP Appendix A, the 38 MMT would implicate approximately 183,000 deaths through 2100, while a linear decline from 2021 to 15 through a 30 MMT 2030 target would implicate approximately 161,000

5. **Comment on the appropriateness of the 38 MMT Core Portfolio as the PSP.**

CalCCA's evaluation of appropriateness of the 38 MMT Core Portfolio (with the Non-Persistence sensitivity) is set forth in the response to Question 3, above.

CalCCA notes, however, that a portfolio's "out" years, especially past 2030, cannot be binding on LSEs in any way, given that the PSP will change again in two years, and that LSEs were not asked to plan for 2031-2032 in their September 2020 filings. Therefore, CalCCA is concerned with statements made in the ALJ Ruling that "[a]ny resources associated with the PSP, or resource attributes thereof, will be *expected to be developed by the LSEs*," and that "[LSEs'] procurement will need to match their emissions and reliability responsibilities associated with the PSP by 2030 and in the interim years."[24] While CalCCA supports the Commission's IRP planning, consistency among the various procurement orders is crucial to providing LSEs with confidence in their procurement planning. For example, while the MTR Order provides a framework for extensions in the procurement of long lead time resources if good cause and a good faith effort to procure are demonstrated by LSEs,[25] the language in the PSP Ruling appears to conflict with that framework and raises concerns that the Commission is considering altering that framework to require the long lead time resources to come online by 2026.[26]

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deaths, while a linear decline to 0 MMT in 245 would implicate approximately 133,000 deaths from the operation of California's energy system. Moving from the proposed PSP to a 2045 decarbonization target would save approximate 50,000 lives.

24 *Id.* at 22 (emphasis added).

25 MTR Decision at 36-38.

26 In fact, as noted by the Commission in the recent Proposed Decision clarifying the confidentiality rules for the renewables portfolio standard program, the average length of time from contract to operation of renewable resources is now approximately 2.3 – 2.6 years, supporting the proposition that resources in the out years do not need immediate procurement actions. *See Proposed Decision Clarifying and Improving Confidentiality Rules for the Renewables Portfolio Standard Program,* R.18-07-003 (Sept. 16, 2021) at 33-34.

6. **Comment on whether the load forecast assumptions should be adjusted to include higher load, particularly related to EV adoption or high electrification more broadly.**

CalCCA supports adjusting the load forecast assumptions to assume the high electrification and EV scenarios, given the carbon-neutrality goals and the state goals that all in-state sales of new passenger cars and trucks will be zero-emission by 2035.[27]

7. **Comment on the proposal to use the 38 MMT Core Portfolio as the reliability and policy-driven base case in the TPP.**

CalCCA supports the base case of 38 MMT Core, with the study and potential adoption of the Non-Persistence sensitivity regarding the PRM in 2026-2030. CalCCA also encourages the Commission to continue the progression of lowering the GHG target in the future to 30 MMT and beyond.

8. **Comment on the proposed policy-driven sensitivity portfolio for the TPP based on the 30 MMT GHG limit in 2030 with the high electrification load assumptions. Suggest any additional or alternative scenarios that should be analyzed as policy-driven sensitivities.**

CalCCA supports the transmittal of an additional sensitivity study to the CAISO to be analyzed for future transmission needs. The sensitivity portfolio of 30 MMT GHG emissions limit in 2030, with the high electrification load assumptions, is appropriate given the need to continue the progression of lower GHG emissions as we get closer to 2045. In addition, the 30 MMT GHG emissions will reflect increased renewable resources. From a policy perspective, the Commission and the CAISO must also consider the interplay of the PSP, the TPP and limitations and delays on bringing projects online related to the CAISO interconnection queue. CalCCA appreciates the Commission advancing this additional sensitivity study that will allow for the necessary time to plan for a lower GHG target with high electrification.

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27 Cal. Executive Order N-79-20.

9. **Comment on whether and how the Commission should act to encourage specific non-transmission alternatives to be built, if identified as part of the CAISO TPP process, both for the two specific projects identified in the 2020-2021 TPP, as well as in general for future such opportunities.**

CalCCA is generally supportive of the ability of non-IOU LSEs to develop storage projects as transmission upgrade alternatives, as well as other potential procurement for transmission system benefit, as long as an appropriate mechanism is developed for such LSEs to recover costs. As recognized in the ALJ Ruling, however, it is unclear whether the Commission is the appropriate entity to order or approve the project and/or the cost recovery for the project. CalCCA assumes the costs for such a project would be recovered through the CAISO's transmission access charge (TAC) approved by the Federal Energy Regulatory Commission (FERC), which would require all LSEs including, IOUs, ESPs, CCAs, and publicly-owned utilities (POUs) within the CAISO to pay for such costs. In addition, entities wheeling through the CAISO should also be required to pay through a FERC approved tariff.

10. **Comment on the options raised in Section 7.2 of this ruling to address procurement for system benefit more broadly. Suggest whether and how a particular cost recovery framework can be adopted quickly or discuss additional considerations that should be explored.**

CalCCA is generally supportive of the ability of non-IOU LSEs to develop projects (such as large and/or long lead time resources) for the benefit of the system (mutual benefit procurement), as long as an appropriate cost recovery mechanism is developed. As set forth in the 2020 Procurement Framework Staff Proposal, the Commission could grant conditional approval for cost recovery, allowing a non-bypassable cost surcharge to be passed on to customers.[28] Resource adequacy credit would be allocated to LSEs for RA showings, based on load share. The cost recovery component would be like the existing Cost Allocation Mechanism

[28] *Staff Proposal for Resource Procurement Framework in Integrated Resource Planning,* CPUC Energy Division (Nov. 18, 2020), at A-64.

(CAM) for utilities, but would allow any LSE to recover costs if they choose to procure the resource.

11. Comment on the busbar mapping approach.

Given the significant amount of renewable energy contemplated by the PSP, as well as the additional renewables that will be required in the future, the busbar mapping process will need to consider land use and siting issues associated with those resources. The significant buildout of solar, wind and battery storage that will be necessary requires land use assumptions to be seriously considered in the process. In addition, the Commission should coordinate with the California Energy Commission regarding land use issues and buildout of new resources.

12. Comment on whether the Commission should require the procurement of resources contained in the individual IRP filings and have LSEs face penalties and/or backstop procurement requirements with cost allocation arrangements, similar to those for D.19-11-016 and D.21-06-035.

CalCCA appreciates the Commission's inquiry into making sure that the LSE plans are actualized in order to ensure the reliability and GHG emissions reductions goals are met. CCAs are using best efforts to procure the resources needed in the short and long term, and have often over procured, allowing such procurement to satisfy subsequently issued Commission procurement orders (as described in the response to question 15, below). In the PSP Ruling, the Commission discusses a "bottom up" approach in which the procurement of the individual IRP planned resources is required for each LSE, with penalties for failure to achieve the capacity and/or energy requirements. A backstop procurement requirement and cost allocation arrangement may also be part of this "bottom up" approach. Alternatively, the Commission proposes a "top down" approach (similar to the procurement orders in D.19-11-016 and D.21-06-035) in which required procurement is allocated to each LSE on a pro-rata basis.

CalCCA agrees that in order to prevent the strained conditions that the market has faced in the past few years, the Commission must ensure that entities are buying forward and using best efforts to meet their procurement targets. However, especially with respect to long lead time resources, entities need sufficient flexibility to pivot based on market circumstances and individual LSE needs. For example, projects may experience delays that make it infeasible to meet targeted online dates despite LSEs contracting with project developers up to their procurement requirement to achieve commercial operation as expeditiously as possible. While LSEs may execute contracts with project developers with delay provisions, circumstances outside the control of the LSE may impact commercial online dates. These circumstances can include supply chain problems, transmission interconnection delays, or COVID-19 impacts, among others.

CalCCA prefers an approach that accounts for the prior action or inaction taken by LSEs in adopting new requirements. Generally, this will lead to a "bottom up" approach in which the needs for the system as a whole (in terms of both reliability and policy goals) are accounted for. The allocation of any need from such a study would then be allocated on the basis of how much an LSE has done within their own portfolio to address those needs. A "top down" approach is incapable of acknowledging prior actions as it simply allocates system needs on a pro-rata basis to all load. Whether the Commission advances the "bottom up" or "top down" approach, it will be critical to evaluate an LSE's progress on the basis of need and not on the basis of their filed plans. For example, a plan filed by an LSE may be above the minimum need that the PSP defined. Penalties for failing to meet such a plan while still meeting the needs of the LSE to comply with their portion of the Commissions adopted need would encourage all LSEs to file a PSP that only meets the bare minimum. For this reason, the Commission must evaluate actual procurement to the Commission defined level of need for the LSE and not on the basis of their filed plan where the filed plan is above and beyond the minimum requirements.

13. Comment on whether you would prefer an approach where the Commission determines procurement need for GHG-free resources or the GHG-free attributes of resources at the system level and then uses a need allocation methodology to assign procurement to individual LSEs. If you propose this type of alternative approach, please address the following aspects:

- **Need allocation, by year**
- **How to address new and existing resources**
- **Whether procurement should be all-source or resource-specific**
- **Resource attributes required (MW, MWh, percentage of GHG-free energy, etc.)**
- **Duration (through 2030, 2032, interim milestones, etc.)**
- **Cost allocation**
- **Compliance, monitoring, and enforcement arrangements.**

CalCCA does not believe there is any reason to deviate from the Commission's current approach in which LSEs have a carbon target that must be attained using the Clean System Power ("CSP") Tool. The CSP Tool not only incentivizes procurement towards the GHG targets, but also incorporates the impact of an LSE's load shape which promotes load modification programs and other incentives for LSEs. A procurement order specifying an amount of GHG-free energy would not incorporate such a load shape.

In addition, CalCCA does not support the resource or technology specific procurement requirements, which prevent flexibility to substitute out resources as markets and/or costs change. Instead, the Commission should specify resource attributes if necessary.

The Commission should also develop a reliability standard with which to evaluate LSE plans. In the last cycle, LSEs received little to no direction on how a plan's contribution to reliability would be measured by the Commission.

14. **If you believe the Commission should take more of a programmatic approach to GHG-beneficial procurement, explain the process you recommend and your rationale.**

    See response to question 13.

15. **Comment on whether and how much procurement required in D.21-06-035 should be accelerated to 2023 and/or suggest additional actions to facilitate additional resources in response to the Governor's Proclamation from July 30, 2021.**

CCAs have moved aggressively to procure new resources, some of which are scheduled to come online in 2022 and 2023 above and beyond the requirements set forth in D.19-11-016. Based on new PPA data provided by its member CCAs, CalCCA estimates that its members will exceed the D.19-11-006 procurement requirements by 208 September NQC MW in 2022, and 649 September NQC MW in 2023. Table 3 below shows the derivation of these values.[29]

Table 3: CCA Procurement for D.19-11-016 Mandate, by resource type (Sep NQC MW)

	2022	2023
Hybrid Solar + Storage	352	911
Standalone Storage	253	253
Wind	137	142
Solar	61	139
Geothermal	12	12
Total NQC MW (sum of lines above)	814	1457
Total D.19-11-016 Procurement Requirement for CCAs	606	808
CCA Procurement in excess of D.19-11-016 requirement	208	649

[29] This table converts nameplate values to NQC values using the September tech factors from the 2021 NQC list, available at http://www.caiso.com/Documents/NetQualifyingCapacityList-2021.xlsx. Storage resources receive their nameplate capacity as NQC, unless they are less than four hours, in which case they are derated (duration in hours / 4 hours). As a conservative assumption, hybrid resources receive only the battery's capacity in NQC – the associated generating unit is ignored.

The resources in excess of the D.19-11-016 requirement, to the extent possible, should count towards a CCAs' procurement requirement for D.21-05-035. In addition, CCAs are using best efforts to accelerate procurement, including the procurement ordered in D.21-05-035 and in response to the Governor's July 30, 2021 proclamation. As stated above in response to question 12, CalCCA does not support the imposition of penalties for existing or any new procurement orders or any additional acceleration of the mandated procurement – rather, the Commission should provide meaningful milestones to measure LSE progress towards procurement, allowing flexibility to the extent necessary.

16. **Comment on the CEC's MTR reliability analysis, the determinations regarding the need for fossil-fueled generation resources, and the actions, if any, that the Commission should take as a result.**

CalCCA is pleased that the Commission is collaborating with the CEC in conducting a LOLE analysis to determine whether additional capacity is necessary beyond the current procurement orders, and to determine whether new gas capacity improves reliability compared to a portfolio of new preferred resources with equivalent NQC values.[30] CalCCA will be submitting comments on October 4, 2021 to the CEC regarding the most recent Midterm Reliability Analysis modeling for the years 2022-2026, provided during the CEC staff workshop on September 23, 2021.

Generally, CalCCA is supportive of the Commission's and the CEC's efforts to conduct an in depth LOLE analysis to inform the PSP. The initial conclusions generated by the MTR reliability study, particularly the conclusion that a portfolio of preferred resources can provide

[30] *See In the Matter of: Midterm Reliability Modeling,* Docket No. 21-ESR-01.

equivalent system reliability to gas resources,[31] are consistent with CCAs' commitment to renewable and preferred resources.

17. **Comment on the definition of eligible renewable hydrogen proposed in this ruling.**

    CalCCA provides no recommendations at this time.

18. **Comment on the percentage of renewable hydrogen facilities that should be required, if any, and the timing of the transition from a blend to full renewable hydrogen combustion, including the option for inclusion of fuel cells. Discuss the feasibility and cost of achieving a 100 percent renewable hydrogen blend by 2036 in your comments.**

The proposal to require specific percentages of renewable hydrogen for any new fossil procurement is premature as the costs for renewable hydrogen are extremely high. Such a policy may be appropriate when the renewable hydrogen market is more mature, as the costs are likely to drop in future. Until then, any fossil procurement that will include renewable hydrogen should be evaluated on its own merits with cost impacts explored.

19. **Comment on proposed measures regarding NOx emissions from facilities using renewable hydrogen.**

    CalCCA provides no recommendations at this time.

20. **Comment on whether the Commission should take any initial actions on geographically-targeted procurement, particularly with respect to Aliso Canyon, or more broadly, and respond to the factors discussed in Section 12 of this ruling.**

    CalCCA provides no recommendations at this time.

21. **Comment on whether and how the Commission should act to preserve transmission deliverability rights in the central coast area that could be utilized for offshore wind or other resources.**

    CalCCA provides no recommendations at this time.

22. **Comment on the amount of offshore wind, if any, that should be included in the 2022-2023 TPP base case. Comment on how the results of the 2021-2022 TPP offshore wind sensitivity case should influence this issue.**

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[31] *See id.,* Presentation, Lead Commissioner Workshop; Midterm Reliability Analysis & Incremental Efficiency Improvements to Natural Gas Power Plants (Aug. 20, 2021).

CalCCA is supportive of studying the potential for additional resources to offset the strained energy conditions in California. However, given that the results of the offshore wind sensitivity portfolio being studied by the CAISO in the 2021-2022 TPP to evaluate transmission needs and costs related to offshore wind at various potential locations off the California coast are not yet available, CalCCA does not support including the offshore wind in the 2022-2023 TPP base case until a CAISO sensitivity study is complete and included in the PSP for analysis. Instead, offshore wind should be studied within the 20-year transmission planning process as a sensitivity to determine the cost effectiveness of such offshore wind resources and the potential transmission needed to support such resources.

23. Comment on whether and how the Commission should act to support the development of OOS renewables/wind and the transmission to deliver it. Be as concrete and specific as possible in your recommendations.

CalCCA is supportive of studying the potential for additional new resources to offset the strained energy conditions in California. However, CalCCA does not support the Commission mandating procurement of resources from a particular state or states, particularly without having the results of the 2021-2022 TPP study which will determine the availability of in-state and out-of-state transmission to support the out-of-state resources. While the Commission assumes that "some amount of additional transmission development will be necessary to facilitate procurement of OOS renewable resources, including wind,"[32] the Commission should delay any action regarding such OOS resources until the necessary transmission and associated costs are known.

24. Comment on specific actions the Commission can take to ensure retention of existing resources needed both for reliability and/or GHG emissions purposes.

CalCCA recommends that the Commission allow procurement of existing resources to count towards future procurement obligations. In order to ensure the retention of existing

[32] ALJ Ruling at 47-48.

resources that the system needs and prevent their retirement, the Commission must incentivize LSEs to re-contract with those resources whose contracts are ending. The easiest way to do this is by allowing LSEs to use contracts with existing or repowered resources to meet part of any future procurement obligations, instead of only allowing the procurement of incremental resources to count towards LSEs' obligations.

25. For any of the potential procurement requirements discussed in this ruling, allocation of need to LSEs is a required step. Comment on how the methodologies should account for in-CAISO POU load and what steps the Commission should take to ensure those POUs bear their share of responsibility for reliability and GHG impacts.

The Commission and CEC should collaborate transparently to exchange information needed to model and account for all LSEs in their respective planning processes and make public any analysis indicating that POU load is contributing to any system shortfalls. This process should leverage the existing parallel POU-IRP process and avoid duplication of planning efforts, especially since the Commission has no jurisdiction over POUs.

III. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments specified herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

Evelyn Kahl
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

September 27, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION REPLY BRIEF

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September 27, 2021

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SUMMARY OF RECOMMENDATIONS

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REPLY BRIEF**

Pursuant to Rule 13.12 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, and the schedule set forth in the *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2* (Scoping Memo)[1], dated August 10, 2021, the California Community Choice Association[2] (CalCCA) submits this reply brief.

I. INTRODUCTION

CalCCA recommended in its Opening Brief[3] that the Commission encourage load-serving entities (LSEs) to expedite procurement of resources available at net peak to a level equivalent to a 17.5 percent planning reserve margin (PRM) rather than adopt major modifications to RA requirements within this proceeding. CalCCA offered this proposal as an alternative to an actual increase of 2.5 percent to the PRM and new net peak requirement, as

1 *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2*, Aug. 10, 2021 (Scoping Memo).

2 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

3 *California Community Choice Association Opening Brief*, Sept. 20, 2021 (CalCCA Opening Brief) at 3-6.

proposed by the California Independent System Operator Corporation (CAISO). This reply brief responds directly to the CAISO's proposal in its opening brief and supports Southern California Edison Company's (SCE's) conclusion that it is too late to make changes to LSEs' 2022 Resource Adequacy (RA) requirements.

II. THE COMMISSION SHOULD ENCOURAGE LSES TO EXPEDITE PROCUREMENT OF RESOURCES AVAILABLE AT NET PEAK TO A LEVEL EQUIVALENT TO A 17.5 PERCENT PLANNING RESERVE MARGIN RATHER THAN ADOPT MAJOR MODIFICATIONS TO RA REQUIREMENTS WITHIN THIS PROCEEDING

CalCCA's Opening Brief expressed support for expediting procurement of resources available at net peak to a level equivalent to a 17.5 percent PRM to the extent possible. Given the expedited timeframe of this proceeding, CalCCA supports a procurement mechanism in which LSEs make best efforts to procure additional supply to support summer reliability, similar to the procurement authorized in Decision (D.) 21-03-056, rather than through modifications to the PRM or RA requirements beginning in 2022.[4] This approach is appropriate for emergency procurement given the uncertainty around how much additional supply is available or can be accelerated in such a short timeframe. CalCCA also supports a review of the PRM and net-peak RA requirements within the RA proceeding, where structural changes to the RA program are already being evaluated. However, given the timeline of this proceeding and uncertainty around the amount of new capacity that can be expedited within that timeframe, the Commission should not make such changes within this proceeding.

The CAISO submitted two proposals that would increase RA requirements for LSEs in 2022 and 2023. The first of CAISO's proposals recommends the Commission set the system RA

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[4] *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022*, March 25, 2021 (D.21-03-056).

requirements to meet demand and the PRM at 8:00 p.m. for June through October, in addition to the current system RA requirement based on the gross monthly peak.[5] The second proposal would increase the PRM from 15 percent to 17.5 percent to account for forced outages and the increased potential for extreme weather events.[6] While RA requirements and associated penalties are important components of the RA program, CalCCA's Opening Brief describes the negative consequences associated with adopting new RA requirements under such a short timeframe.[7] Specifically, such modifications would increase penalties and associated customer costs without certainty incremental supply will be available for LSEs to procure to meet their requirements.

The CAISO stated in their Opening Brief modifications to the RA program are necessary to allow the CAISO to use its Capacity Procurement Mechanism (CPM) authority more effectively.[8] On June 29, 2021, Commission President Marybel Batjer and California Energy Commission Chair David Hochschild sent the CAISO a joint letter requesting the CAISO exercise its CPM authority to procure additional capacity for summer 2021.[9] The CAISO stated, "… when the CAISO initiated its CPM procurement in July following receipt of the joint letter, there were limited supplies available—much less than the amount the CAISO identified as necessary to ensure reliability." It further suggested the Commission "get ahead of the curve" by adopting new RA requirements because conditions are expected to be tight again in 2022.[10] Despite its efforts to encourage the Commission to take action, the CAISO's experience

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5 *Opening Testimony of the California Independent System Operator Corporation*, Section III, Sept. 1, 2021 (CAISO (Billinton)), at 2:7 – 2:16.

6 *Id.*, Section IV, Sept. 1, 2021 (CAISO (Mohammed-Ali)), at 12:3 – 12:5.

7 CalCCA Opening Brief at 4-6.

8 *Opening Brief of the California Independent System Operator Corporation*, Sept. 20, 2021 (CAISO Opening Brief) at 10.

9 http://www.caiso.com/Documents/CapacityProcurementMechanismSignificantEvent-JointStatementandLetter.pdf

10 CAISO Opening Brief at 11.

highlights the challenges LSEs will face when attempting to expedite procurement on such a short timeframe. The results of this CPM procurement demonstrate supply conditions are extremely tight, and the challenges the CAISO faced procuring additional resources for this summer will similarly be faced by LSEs attempting to procure for next summer. It is unclear how increasing RA requirements will increase supply at this late date such that LSEs will have the ability to meet the new requirements.

Additionally, CalCCA agrees with Southern California Edison Company (SCE) that it is too late to make changes to LSEs' RA obligations for 2022, as a practical matter.[11] As SCE explains in its Opening Brief, LSEs have already procured to meet their year-ahead RA obligations for 2022. Introducing a new RA requirement at such a late stage could disrupt procurement already complete and leave LSEs unclear or unable to meet their RA requirements. First, year-ahead showings must be submitted by the end of October, prior to the expected final decision for this proceeding per the Scoping Memo.[12] Additionally, as CalCCA describes in its Opening Brief, increasing RA requirements at this late stage will not result in increased supply by 2022, given the limited time to make any meaningful increases in supply by summer 2022.[13] If the Commission determines additional capacity is needed for 2022, the Commission should adopt "effective" targets for all LSEs in this proceeding, rather than modifying their RA obligations.

III. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests the Commission adopt CalCCA's recommendation to encourage LSEs to expedite procurement of resources available at

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11 *Southern California Edison Company's (U 338-E) Opening Brief*, Sept. 20, 2021 (SCE Opening Brief) at 58.

12 Scoping Memo at 6.

13 CalCCA Opening Brief at 6.

net peak to a level equivalent to a 17.5 percent planning reserve margin rather than adopting major modifications to RA requirements within this proceeding.

Respectfully submitted,

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ASSOCIATION

September 27, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	Rulemaking 18-07-005 (Filed July 12, 2018)

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION AUTHORIZING PERCENTAGE OF INCOME PAYMENT PLAN PILOT PROGRAMS

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September 27, 2021

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SUMMARY OF RECOMMENDATIONS

- Adopt the PD's allowance of CCA participation in the PIPP Pilot;
- Delay the commencement of the PIPP pilot in SDG&E's territory to no sooner than July 1, 2022 due to the transfer of customers from SDG&E to SDCP through June 2022;
- Define the rules for a new or expanded CCA for which customers already enrolled in the PIPP pilot by the IOU are transferred to CCA service;
- Require PIPP pilot income verification for all customers, including those in the 101-200 percent Federal Poverty Level tier, prior to enrollment in the PIPP pilot;
- Require all administrative costs of the PIPP pilot be subject to reasonableness review; and
- Adopt the 48-month term for the PIPP pilot set forth in the PD.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	Rulemaking 18-07-005 (Filed July 12, 2018)

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION AUTHORIZING PERCENTAGE OF INCOME PAYMENT PLAN PILOT PROGRAMS

The California Community Choice Association (CalCCA)[1] submit these comments pursuant to Rule 14.3(d) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the *Proposed Decision Authorizing Percentage of Income Payment Plan Pilot Programs* (PD), issued on September 2, 2021.

I. INTRODUCTION

CalCCA appreciates the opportunity to provide these reply comments, which address issues raised in opening comments that CalCCA did not previously discuss. CalCCA does not change its position on any of the topics that it raised in opening comments, but rather uses this opportunity to expand or address additional issues.

As set forth in more detail below, CalCCA recommends that the Commission:

- Adopt the PD's allowance of CCA participation in the PIPP Pilot;
- Delay the commencement of the PIPP pilot in SDG&E's territory to no sooner than July 1, 2022 due to the transfer of customers from SDG&E to SDCP through June 2022;
- Define the rules for a new or expanded CCA for which customers already enrolled in the PIPP pilot by the IOU are transferred to CCA service;
- Require PIPP pilot income verification for all customers, including those in the 101-200 percent Federal Poverty Level tier, prior to enrollment in the PIPP pilot;
- Require all administrative costs of the PIPP pilot be subject to reasonableness review; and
- Adopt the 48-month term for the PIPP pilot set forth in the PD.

[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

II. THE COMMISSION SHOULD ADOPT THE PD'S ALLOWANCE OF CCA PARTICIPATION IN THE PIPP PILOT

The PD allows CCAs to participate in a utility's PIPP pilot.[2] The Utility Consumers' Action Network (UCAN) argues in its opening comments that the CCAs should not be given an option to participate, but should rather either be excluded from the PIPP pilot altogether, or should be required to participate. UCAN bases its arguments on a concern that the exclusion of a portion of low-income customers from participating in the pilots (if a CCA chooses not to participate) could impact the evaluation and results of the pilots.

UCAN's proposal to exclude CCAs altogether is inherently flawed and would result in the exact result that UCAN fears. CCAs account for over 4 million customer accounts, or 32 percent of the load in the territories of Pacific Gas and Electric Company (PG&E), Southern California Edision Company (SCE) and SDG&E combined.[3] Excluding CCAs from the PIPP pilot would therefore prevent a substantial number of eligible customers from benefitting from the PIPP pilot. In addition, excluding CCA customers would result in incomplete PIPP pilot data, rendering any evaluation of the pilot less effective in determining whether and how to implement a long term PIPP. Finally, excluding CCA customers from eligibility for the PIPP pilot would unfairly require CCA unbundled customers to pay for the PIPP pilot (through the Public Purpose Programs Charge (PPPC)) without eligible CCA customers being able to benefit from it.

UCAN argues that providing CCAs the option to participate in the PIPP constitutes legal error based on Public Utilities Code sections 453(a) and (b), which prohibits utilities from providing service on a preferential or discriminatory basis.[4] Notwithstanding that CCAs are not "utilities" under the Public Utilities Code, the decision of a CCA over whether to participate in the PIPP pilot has nothing to do with preferential or discriminatory practices, but rather is related to the ability of CCA to participate, or whether its governing board has authorized participation.

In any event, many CCAs are eager to participate in the PIPP pilot to benefit their customers in need, and will be notifying all members of the service list of their participation within 30 days of the final decision as directed by the PD. Accordingly, the Commission should reject UCAN's arguments and adopt the PD which allows CCAs to participate in the PIPP pilot.

III. THE COMMISSION SHOULD DELAY THE COMMENCEMENT OF THE PIPP PILOT IN SDG&E'S TERRITORY TO NO SOONER THAN JULY 1, 2022

As set forth in SDG&E's Opening Comments, SDG&E's service territory is in a unique situation, in that approximately 47 percent of SDG&E's residential customers will be transitioning to service with a CCA, SDCP,

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2 PD at 78, Conclusion of Law (CoL) 11.

3 This number will rise by close to 1 million customers when SDG&E customers transition to SDCP in 2022.

4 Cal. Pub. Util. Code §453.

between February and June of 2022.[5] SDG&E raises the potential for conflicts between the PIPP pilot's current schedule and the transfer of customers from SDG&E to SDCP. In addition, SDG&E points out that new California Alternate Rates for Energy (CARE) income eligibility guidelines will be available as of June 1, 2022, creating the potential for even more customer confusion. As a result, CalCCA requests that the Commission adopt SDG&E's proposal for the PIPP pilot to begin in SDG&E's territory no sooner than July 1, 2022. In addition, CalCCA requests that the Commission allow SDCP to participate in the PIPP pilot if it is participating in AMP as of the time it begins residential service.

IV. THE COMMISSION SHOULD DEFINE THE RULES FOR A NEW OR EXPANDED CCA FOR WHICH CUSTOMERS ALREADY ENROLLED IN THE PIPP PILOT BY THE IOU ARE TRANSFERRED TO CCA SERVICE

SDG&E requests that the PD be clarified regarding how the proportional allocation of customers enrolled in the PIPP pilot in its territory will work during and after the transfer of customers to a CCA.[6] For CCAs who begin the PIPP pilot with their proportional share of customers, the PD requires that proportional share be a cap for that CCA's participation.[7] However, in the case of a transfer of customers from an IOU to a CCA after the initial enrollment for the PIPP, SDG&E proposes that the proportional share should be a target and not a cap (as long as the total customers enrolled in the IOU service territory is capped as set forth in the PD). CalCCA requests that the Commission adopt SDG&E's proposal not only for SDG&E's territory, but for any situation in which a CCA is newly established or has expanded its territory during the PIPP pilot. Allowing the flexibility of a target rather than a cap for the proportional share in this instance will ensure customers enrolled in PIPP get to stay enrolled even if they transfer from an IOU to a CCA.

For new CCAs to which PIPP enrolled customers are transferred, the Commission should also allow an exception to the requirement that a CCA be participating in AMP at the time of the issuance of the Decision, but should rather require a new CCA to be participating in the AMP when its begins residential service.

V. INCOME VERIFICATION SHOULD BE REQUIRED FOR ALL PIPP PILOT CUSTOMERS PRIOR TO ENROLLMENT

The PD requires participants in the 101-200 percent Federal Poverty Level (FPL) category to be subject to the CARE post-enrollment verification processes.[8] CalCCA supports SDG&E's proposal that instead of utilizing the CARE post-enrollment verification processes in which the utility verifies a minimal percentage of the self-verifying customers, that *all* PIPP pilot customers be required to verify their income prior to enrollment in the PIPP

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5 SDG&E Opening Comments at 7 (citing San Diego Community Power's Phase 3 Customer Enrollment Schedule, as adopted by the SDCP Board of Directors on Apr. 22, 2021)).

6 SDG&E Opening Comments at 7.

7 Proposed Decision, Conclusion of Law 11, at 78-79.

8 Proposed Decision Conclusion of Law 6.d.. at 77.

pilot.[9] Verification of all customers, whether in the 0-100 percent FPL category or the 101-200 percent FPL category, will not only ensure accurate data for proper evaluation of the success of the PIPP in lowering disconnections, but will also ensure true eligibility for all customers needing the assistance. In addition, CalCCA supports SDG&E's proposal to clarify alignment of the PIPP verification and CARE certifications to allow a customer to get verified for PIPP, and then recertify when the CARE certification is due.[10]

VI. THE COMMISSION SHOULD REJECT PG&E'S REQUEST TO ONLY HAVE ADMINISTRATIVE COSTS IN EXCESS OF ITS BUDGET REVIEWED FOR REASONABLENESS

The PD orders utilities to record all administrative costs in a PIPP memorandum account, subject to reasonableness review.[11] PG&E requests the Commission approve a budget at the "low end of the forecast" for its administration of the PIPP pilot ($3.59 million for PG&E), and require any costs above the budget be subject to reasonableness review.[12] As demonstrated in the table below, the estimated costs for administration of the PIPP Pilot (based on the costs estimated by the utilities for the Straw Proposal) varies greatly among the utilities:

Utility	Straw Proposal # Customers	Estimate for Administrative Costs for PIPP Pilot as Described in Straw Proposal[13]
PG&E	5,000	Between $3.59 million – $13.69 million
SCE	4,000	Between $1.4 million – $4.3 million
SDG&E	1,000	$3.4 million – $6.9 million
SoCalGas	5,000	$1.658 million

CalCCA agrees with the Commission that given the wide variation in types and values of administrative costs, all such costs should remain subject to reasonableness review. Accordingly, CalCCA recommends adoption of the PD's requirement regarding review of all administrative costs, and not just those above a budgeted amount as requested by PG&E.

9 SDG&E Opening Comments at 3-4.
10 *Id.* at 5-6.
11 PD at 87-88, Ordering ¶11.
12 PG&E Opening Comments at 2-3.
13 *Pacific Gas and Electric Company's (U 39 M) Opening Comments on the Percentage of Income Payment Straw Proposal (July 9, 2021),* Rulemaking (R.) 18-07-005, at 26, Table 3; *Southern California Edison Company's (U 338-E) Comments on Percentage of Income Payment Straw Proposal* (July 9, 2021), R.18-07-005, at 12, Table 2; *Comments of San Diego Gas & Electric Company (U 902 M) to the PIPP Pilot Straw Proposal* (July 9, 2021), R.18-07-005, at 7; *Comments of Southern California Gas Company (U 904 G) to Administrative Law Judge's Ruling Regarding the Percentage of Income Payment Plan (PIPP) Straw Proposal* (July 9, 2021), R.18-07-005, at 7.

VII. UCAN'S REQUEST TO SHORTEN THE PILOT SHOULD BE REJECTED

UCAN requests that the PIPP pilot be shortened from 48 months to 24 months, based on the imminent need for a state-wide PIPP program to respond to the arrearage/disconnection crisis.[14] The substantial utility arrearages resulting from the impacts of the COVID pandemic are currently being addressed by multiple relief programs, including the California Arrearage Payment Plan (CAPP),[15] other federal and state covid relief, COVID-19 payment plans,[16] and the AMP.[17] The PIPP is being conducted as a pilot to analyze whether it prevents disconnections based on robust data from the pilot. The substantial cost of the program to all customers, who pay for the subsidy through the PPPC, demands the validation of the pilot to ensure the PIPP is effective. Given that the enrollment alone of PIPP pilot customers will take at least 6 months, data adequate for a determination of whether to roll out the PIPP to all eligible customers must be robust and be based on years, and not months, of data. In addition, given the substantial impact of the COVID pandemic, 48 months gives adequate time for a post-COVID "adjustment" for the economy which will allow for a better indication of the program's likely success.

VIII. CONCLUSION

CalCCA appreciates the opportunity to submit these reply comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

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September 27, 2021

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14 UCAN Opening Comments at 8.

15 Cal. Govt. Code §16429.5 (establishing the CAPP).

16 *See Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* Decision (D.) 21-06-035 (June 24, 2021) (establishing COVID-19 Relief Payment Plans).

17 *See Phase 1 Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-Jurisdictional Energy Utilities,* D.20-06-003 (June 11, 2020) (establishing the AMP).

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 18-07-003 (Filed July 12, 2018)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) TO UPDATE ITS DRAFT 2021 RENEWABLE ENERGY PROCUREMENT PLAN

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On behalf of
California Community Choice Association

September 28, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 18-07-003 (Filed July 12, 2018)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) TO UPDATE ITS DRAFT 2021 RENEWABLE ENERGY PROCUREMENT PLAN

In accordance with Rule 11.1(e) of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), California Community Choice Association[1] ("CalCCA") respectfully submits this response to Pacific Gas and Electric Company's ("PG&E") motion to update its Draft 2021 Renewable Energy Procurement Plan ("Motion to Update") filed in this proceeding on September 13, 2021.[2] This response is timely filed pursuant to Rule 11.1(e).

By its Motion to Update, PG&E requests the Commission authorize it to submit the pro forma contract to be used in the Voluntary Allocation of renewables portfolio standard ("RPS")

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] PG&E filed its motion to update pursuant to the March 30, 2021 *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2021 Renewables Portfolio Standard Procurement Plans*, filed in this proceeding ("2021 RPS Plan Ruling"), as updated by Administrative Law Judge Ruling, dated July 22, 2021, revising the procedural schedule for the 2021 Renewables Portfolio Standard ("RPS") Procurement Plans.

resources ("Voluntary Allocation Contract") via a Tier 2 Advice Letter "within 10 days of the submission of its Final 2021 RPS Procurement Plan."[3] Further, PG&E requests further authority to submit the pro forma contract to be used in the subsequent market offer of RPS resources remaining in its portfolio after the voluntary allocation ("Market Offer Contract") for approval within 45 days of submission of its Final RPS Procurement Plan.[4] PG&E notes that its Final 2021 RPS Procurement Plan "is likely to be submitted in early 2022."[5]

CalCCA appreciates PG&E's willingness to submit the Voluntary Allocation Contract for early review, and for recognizing that this pro forma contract must be agreed to and approved before LSEs are required to make their election to either accept or decline their allocation of RPS resources. CalCCA also agrees with PG&E that a Tier 2 advice letter process is appropriate for review of the contracts to be used in the Voluntary Allocation and Market Offer ("VAMO") process. To ensure a reasonable time period for potential counterparties to review, consider, and comment on the proposed terms and conditions of the Voluntary Allocation and Market Offer Contracts, CalCCA requests the Commission require PG&E to host at least two workshops on the proposed terms and conditions of these contracts prior to the submission of the advice letter seeking their approval. To accommodate these workshops, CalCCA requests the Commission require PG&E to submit the Voluntary Allocation Contract and Market Offer for counterparty review no later than 45 days prior to the deadline for LSEs to make their election to accept or decline their voluntary allocations.

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3 PG&E Motion to Update at 2.

4 *Id*. at 3.

5 *Ibid*.

I. PG&E SHOULD SUBMIT THE VOLUNTARY ALLOCATION CONTRACT AND MARKET OFFER CONTRACT FOR COUNTERPARTY REVIEW NO LATER THAN 45 DAYS PRIOR TO THE DEADLINE FOR LSES TO MAKE THEIR ELECTION TO ACCEPT OR DECLINE THEIR VOLUNTARY ALLOCATIONS

As PG&E notes, LSEs will be required to make their election regarding their voluntary allocation by May 2022.[6] Because no firm date has been established for the delivery of PG&E's Final RPS plan, submittal of the Voluntary Allocation Contract "within 10 days" of that plan does not guarantee adequate time for potential counterparties to review the proposed terms and conditions in that contract.

Prior to making the decision to accept or decline the voluntary allocation offered to them, LSEs must determine whether the terms and conditions of that offer align with their individual programmatic goals as well as the requirements of Decision ("D.") 21-05-030. Under no other circumstances would an LSE be required to make a commitment to "purchase" without first seeing all relevant contracts in their entirety. LSE counterparties thus must have a reasonable opportunity and period in which to review and consider the proposed Voluntary Allocation Contract. To ensure optimum participation in the VAMO process, and thereby achieve the portfolio optimization goals for which it was designed, LSEs must receive the proposed Voluntary Allocation Contract well in advance of the date on which they must make their elections.

CalCCA therefore requests the Commission establish a firm date for the submission of the proposed contracts for review by potential counterparties. CalCCA requests the Commission require PG&E to submit both the Voluntary Allocation Contract and the Market Offer Contract for counterparty review no later than 45 days prior to the deadline for LSEs to make their

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6 *Ibid*.

elections. CalCCA notes there is no reason to wait until the Final 2021 RPS Plan is filed, as the contract terms and format do not depend on that plan being finalized. This schedule will permit time for counterparty review, comment, and discussion of the proposed terms through a workshop process, discussed below.

II. PG&E SHOULD HOLD AT LEAST TWO WORKSHOPS PRIOR TO ISSUANCE OF THE ADVICE LETTER SEEKING APPROVAL OF THE VOLUNTARY ALLOCATION CONTRACT AND MARKET OFFER CONTRACT

The VAMO process is new for all parties involved. While the Voluntary Allocation Contract will undoubtedly be based on pro forma contracts approved for IOU use in other contexts, the specific terms of the voluntary allocations themselves are, by definition, new. Because the review of these terms and conditions bears so significantly on an LSE's decision whether to accept or decline the RPS allocation, CalCCA urges the Commission to require PG&E to hold at least two workshops on the proposed terms and conditions of the Voluntary Allocation Contract prior to PG&E's submittal of the advice letter seeking its approval.

The Commission also needs to consider the interaction between the Voluntary Allocation and the subsequent Market Offer Contract. The decision of a party to take its voluntary allocation (particularly for a long-term allocation) will be influenced by the relative costs and terms and conditions of the Market Offer Contract as an alternative. Accordingly, CalCCA urges the Commission to require PG&E to include the proposed terms and conditions of the Market Offer Contract in these workshops, as well.

The advice letter process itself, which is necessarily time-compressed, does not provide a forum for dialogue between potential counterparties regarding the specific terms to be agreed. A workshop setting would be an appropriate venue for PG&E to present the proposed terms and conditions to potential counterparties. Parties will have the opportunity to pose questions, and

PG&E can receive feedback on the proposed terms and conditions. All potential counterparties would benefit from an early familiarization with the contracts they will be asked to sign.

III. CONCLUSION

For the reasons stated above, CalCCA respectfully requests the Commission adopt its recommendations as set forth herein.

Respectfully submitted,

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On behalf of
California Community Choice Association

September 28, 2021

Submit comment on Issue Paper

Initiative: External load forward scheduling rights process

1. Please provide your organization's perspective on the proposed Phase 1 scope items and timeline described in the issue paper:

The Joint CA LSEs are disappointed by the CAISO's decision to reject our proposed interim framework. The current scheduling parameters do not appropriately prioritize CAISO BAA reliability, and we do not support the CAISO's proposed timeline, which will leave this interim solution in place until 2024. We believe that any near-term enhancements proposed within Phase 1 should improve CAISO BAA reliability beyond the current scheduling parameters and be implementable by June 1, 2022.

It is essential that the CAISO set realistic expectations for implementation and ensure that the current tariff provisions remain in place after the May 31, 2022 sunset date. Our understanding is that the near-term enhancements will build off those provisions; however, we are concerned that some items that the CAISO has identified as in scope for this initiative, such as changes in curtailment deadlines and changes in market systems related to high priority ("PT") exports, may pose significant implementation challenges. Our concern is that the failure to develop and implement at least some elements of these Phase 1 items could lead to a scenario where the previously-applicable penalty parameters are re-implemented temporarily, leading to significantly decreased reliability for a portion of next summer. This result is unacceptable to the Joint CA LSEs. As such, the CAISO must consider its timeline carefully and evaluate options for tariff filings to ensure that the current penalty parameters remain in effect until replacement provisions are implemented.

The Joint CA LSEs support the CAISO's inclusion of a solution to mitigate impacts of underproduction of resources supporting PT exports. We look forward to working collaboratively with the CAISO to find a viable solution.

The Joint CA LSEs are concerned that a Day-Ahead E-Tag requirement could lead to market power concerns related to the availability of transmission on external systems as well as create a new seams issue. It appears that the majority of the transmission rights leading to COB and NOB are held by a limited group of entities that may have the ability to exert market power if parties were required to procure transmission in the Day-Ahead timeframe. Also, a Day-Ahead E-Tag requirement would be inconsistent with current NERC requirements across the West, thereby creating an additional seams issue. For these reasons, we do not currently support a Day-Ahead E-Tag requirement. The suggestion to move the pro rata curtailment allocation to after the T-20 deadline, as outlined in comments submitted by Shell Energy North America (US), L.P. ("Shell"), could have some merit, but the Joint CA LSEs are reserving any substantive comments on the Shell approach until after a more detailed proposal is available.

2. Provide your organization's suggestions on any additional near-term enhancements that should be considered as part of the initiative Phase 1 scope:

The Joint CA LSEs encourage the CAISO to consider changes to the tariff to better define what should be treated as Resource Adequacy capacity. Specifically, we ask the CAISO to address the comments made by the CPUC Energy Division regarding the fact that RMR and CPM resources are not currently treated as RA capacity in the post-HASP allocation. For the purpose of Phase 1 scoping, we ask that the CAISO consider if these resources should be treated as RA capacity in the allocation. At this time, the Joint CA LSEs believe that the comments offered by the CPUC Energy Division have merit. There appears to be no valid reason not to treat these resources comparably to RA capacity in the post-HASP allocation process; indeed, these resources share many of the same performance obligations as RA capacity, and LSEs within the CAISO are funding the performance of these resources' CPM and RMR obligations. As such, RMR and CPM resources should be prepared to participate fully in all of the CAISO's market processes, to be subject to comparable offer and participation obligations, and to provide all of their reliability attributes to the CAISO in exchange for the capacity payments that they recoup pursuant to the RMR and CPM programs. It is equally important that the CAISO ensure deliverability of these resources at the same level of priority as RA resources.

3. Provide your organization's perspective on Phase 2 scope of the initiative and timeline - the development of a forward transmission reservation process for establishing scheduling priorities in the market:

The Joint CA LSEs support the CAISO's plan to pursue a forward transmission reservation process that will allow for reasonable native load protection and respect existing CAISO market frameworks. The key components of the process that the CAISO has thus far identified seem reasonable and consistent with our understanding of the common practices of other BAAs and RTOs/ISOs.

The Joint CA LSEs ask the CAISO to provide more detail regarding the processes that overlap with this initiative (e.g. Transmission Planning Process and Congestion Revenue Rights Auction and Allocation Process) and their respective timelines. Acknowledging that at this early stage the exact scope of the proposal is not known, it would be helpful to understand when changes to these overlapping processes would be required in order to operationalize the Phase 2 proposal.

4. Provide your organization's perspective on the guiding principles for the development of a long-term, holistic, framework for establishing scheduling priorities in the market:

The Joint CA LSEs would like to underscore the importance of reserving adequate capacity to meet native load requirements. We again emphasize that, similar to every other BAA and as prescribed by FERC policy[1], BAAs can reserve transmission capacity in order to reliably serve their native load. Only after a BAA is confident that it is able to serve its native load is it required to provide broader access to its system. Ensuring that the CAISO BAA can reliably serve native load will be paramount in fostering participation in the potential expansion of the CAISO market across the West.

The Joint CA LSEs would also like to point out that, while minimizing seams issues between the CAISO market and OATT BAAs may be desirable, *eliminating* seams issues will not be possible, nor should it be the goal of this initiative. The basic framework proposed by the CAISO should reduce some of the most significant seams issues. The Joint CA LSEs ask that the CAISO, however, work

[1] "We conclude that the native load priority established in Order No. 888 continues to strike the appropriate balance between the transmission provider's need to meet its native load obligations and the need of other entities to obtain service from the transmission provider to meet their own obligations." FERC Order 890 P. 107.

toward solutions that are in alignment with the CAISO market structure instead of reverting to the OATT model. Rather, the Joint CA LSEs urge the CAISO to work cooperatively with neighbors to evaluate ways in which their market participation may advance beyond the OATT model.

5. Provide your organization's perspective on the structure of the suggested stakeholder working groups proposed to further vet aspects of the forward transmission reservation process:

In these workshops, the CAISO should determine its own processes, consistent with open access principles, and bearing in mind its core obligation of ensuring reliability to the load within its Balancing Authority Area. The Joint CA LSEs are concerned by the currently-proposed structure of the working groups, which appears to provide external entities with a potentially outsized influence on topics that affect the CAISO BAA. While we certainly see the value in learning from the practices of other BAAs, we do not believe that neighboring BAA processes or these stakeholders should dictate the outcomes of this stakeholder proceeding, which addresses terms and conditions for access to and scheduling rights over the CAISO-controlled transmission system, including assets owned by Participating Transmission Owners in the CAISO (which include nine of the Joint CA LSEs). In particular, when determining how much capacity on the CAISO transmission system is necessary to serve CAISO native load, we urge the CAISO to ensure the conversation is appropriately balanced and focused on the needs of CAISO BAA stakeholders. It is these stakeholders for which the CAISO transmission system has been planned, and it is these stakeholders that have paid for the costs of the CAISO transmission system. Most importantly, it is these stakeholders that depend on the CAISO transmission system to meet the needs of their customers in every hour of every day. In attempting to perform outreach for the purpose of accommodating the emerging desires of neighboring systems to procure external power supply and wheel it across the CAISO based on scheduling priorities that could very well impair reliability to CAISO native load, the Joint CA LSEs strongly urge the CAISO to appropriately weigh the views and perspectives of entities within the CAISO BAA.

To provide transparency and allow for a robust discussion, the Joint CA LSEs support the CAISO opening the working groups up to a public audience. We believe that external BAAs should have no significant concerns about describing their processes and terms for transmission access on their systems in detail within a public workshop. These rules should be set forth in their own public tariffs and related business practice documents such that there should be no concerns regarding confidentiality.

One topic that does not appear to be within the scope of any of the identified workshops is the development of the appropriate rates and charges for forward reservation of scheduling priorities. The CAISO should further detail how it will address this topic within the scope of the three proposed working groups. If this is not adequately addressed in the scope of the proposed working groups, the Joint CA LSEs recommend that this topic form the subject of a separate workshop scheduled to occur following the development of the long-term framework for establishing scheduling priorities.

6. Provide your organization's perspective on the EIM decisional classification for the initiative:

The Joint CA LSEs agree that this initiative is out of the scope of Joint Authority and that the EIM Governing Body has an advisory role on this initiative.

7. Provide your organization's perspective on any other aspects of the issue paper and initiative:

No additional comments.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

OPENING BRIEF OF MARIN CLEAN ENERGY

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September 20, 2021

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

Statutes

Commission Rules of Practice and Procedure

Commission Decisions

SUMMARY OF RECOMMENDATIONS

On the supply side, Marin Clean Energy ("MCE") urges the Commission to:

- Require that any late-stage resource adequacy ("RA") program changes adopted on an emergency basis in this proceeding still follow the emergency process that the Commission adopted in Decision ("D.") 21-03-056, and assign these late-stage procurement requirements to the Investor-Owned Utilities ("IOUs") using the Cost Allocation Mechanism ("CAM") for the duration of the emergency.
- Impose penalties for resource adequacy ("RA") deficiencies, if the Commission assigns late-stage RA program procurement requirements to all Load Serving Entities ("LSE").

On the demand side, MCE urges the Commission to:

- Empower MCE and other community choice aggregators ("CCAs") to maximize demand response ("DR") utilization to serve their customers' loads.
- Authorize ratepayer funding to leverage three MCE programs that present a cost-effective, low-hanging fruit opportunity to achieve peak demand reductions in time for summers 2022 and 2023, as shown in Table 1 below:

<u>Table 1</u>: MCE Program Peak Demand Reduction Potential.

	Peak Demand Reduction Potential (MW)		**Budget Request ($)**
	2022	**2023**	
Peak FLEXmarket	15	30	$11,560,000
Energy Storage Program	2	3.8	$4,408,000
MCEv Sync	2.5	5	$1,776,000
TOTAL	**19.5**	**38.8**	**$17,744,000**

- Reject auto-enrollment provisions for IOUs' Demand DR programs, and instead implement policies that will support a level-playing field across DR providers, including CCAs. CCAs have developed innovative programs tied to their customers' needs and are poised to deliver significant load-reduction benefits.

- Direct quarterly data sharing of DR program enrollment and other relevant data between IOUs and CCAs to streamline program development, customer enrollment, and to avoid dual participation issues and customer confusion. Convene a stakeholder workshop to develop the data sharing guidelines as needed.
- Continue to leverage smart control thermostats ("SCTs") as a key component of customer engagement by maintaining existing support for local SCT program funding and avoiding shortsighted limitations on SCT installations.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

OPENING BRIEF OF MARIN CLEAN ENERGY

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and Commissioner Batjer's August 10, 2021 Amended Scoping Ruling ("Amended Scoping Ruling"),[1] MCE hereby submits this opening brief in Phase 2 of the above-captioned *Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021* ("Rulemaking").[2]

The Amended Scoping Ruling establishes the scope for this Phase 2 and invites party comment on ways to address Governor Newsom's July 30, 2021 Emergency Proclamation ("Emergency Proclamation"),[3] which directed all state agencies "to act immediately" to find ways to make up for the "projected energy supply shortage of up to 3,500 megawatts ["MW"] during the afternoon-evening 'net-peak' period of high power demand on days where there are extreme weather conditions."[4] The purpose of this Rulemaking is to identify ways to both increase energy

1 Rulemaking ("R.") 20-11-003, *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2*, p. 6 (August 10, 2021) ("Amended Scoping Ruling").

2 *See* Amended Scoping Ruling, p. 3 ("This phase of the proceeding will be known as 'Phase 2 – Reliability for 2022-23 – Update' (Phase 2).")

3 Proclamation of a State of Emergency ("Emergency Proclamation"), July 30, 2021, *accessible at*: https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.

4 *Id*.

supply and to decrease demand during the peak demand and net peak demand hours in 2022 and 2023.[5] Phase 2 also invites consideration of "changes to current [Commission] requirements" that might be "needed to meet Governor Newsom's emergency proclamation."[6]

I. INTRODUCTION

MCE, California's first CCA, is a not-for-profit public agency that began service in 2010 with a mission of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs.[7] MCE is a LSE serving approximately 1,200 MW of peak load, providing electricity generation services to more than 1.1 million people in 36 member communities across Contra Costa, Marin, Napa, and Solano counties.[8]

In this opening brief, MCE addresses both supply-side and demand-side issues and policy recommendations that can improve grid reliability under extreme weather conditions in the summers of 2022 and 2023.

On the supply side, given the current emergency situation, MCE recommends that the Commission: (1) assign any late-stage RA program changes that increase RA program procurement to the IOUs, and (2) allocate the costs for the RA-eligible procurement to all LSEs using CAM for the duration of the emergency. This approach positions the state to protect ratepayers from unnecessary spikes in RA costs caused by the emergency nature of the procurement and best ensures that additional RA-eligible capacity is procured. MCE also emphasizes the importance of penalties in the event the Commission assigns late-stage RA

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5 Amended Scoping Ruling, pp. 3-4; *see also Assigned Commissioner's Scoping Memo and Ruling* (December 21, 2020), p. 1.

6 Amended Scoping Ruling, p. 4.

7 *MCE Prepared Direct Testimony of Alice Havenar-Daughton in Rulemaking 20-11-003* (September 1, 2021), p. 1-2:4-7 (hereafter "MCE Phase 2 Testimony").

8 MCE Phase 2 Opening Testimony, p. 1-2:4-9.

procurement requirements to all LSEs. Penalties can best incentivize all LSEs to procure aggressively and reduce instances of leaning and cost-shifting among LSEs.

On the demand-side, MCE is well positioned to provide substantial value through its existing demand flexibility programs, which can serve as an integral tool to achieve the peak demand reduction and grid reliability goals espoused in the Governor's Emergency Proclamation. MCE has already developed and launched (with its own ratepayer funding) several demand flexibility programs that, with adequate additional funding, can be leveraged and scaled to quickly address the energy supply shortage identified in the Emergency Proclamation. MCE urges the Commission to approve ratepayer funding to advance these programs and further encourages the Commission to implement policies under this Rulemaking that will ensure CCA DR programming is not undercut by monopolization of DR programs by the IOUs.

II. SUPPLY-SIDE ISSUES

A. LATE-STAGE EMERGENCY RA PROGRAM CHANGES THAT INCREASE PROCUREMENT REQUIREMENTS OR CREATE NEW COMPLIANCE REQUIREMENTS SHOULD BE ASSIGNED TO THE IOUS FOR THE DURATION OF THE EMERGENCY PERIOD VIA THE CAM.

MCE agrees with testimony in the record that the Commission should not adopt additional mandated supply-side procurement or new RA compliance requirements in this proceeding,[9] and that any changes to the RA program are more appropriately addressed and adopted in the RA proceeding.[10] However, if the Commission adopts emergency, late-stage RA program changes in this proceeding, in the interest of ratepayers and efficient emergency reliability procurement, the Commission should follow the emergency process it adopted in Decision ("D.") 21-03-056 and

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9 *See Reply Testimony of Marie Y. Fontenot on Behalf of the California Community Choice Association* ("CalCCA") (September 10, 2021), p. 5; *see also Direct Testimony of Southern California Edison Company-Phase 2* ("SCE") (September 1, 2021), p. 57 (hereafter SCE Phase 2 Direct Testimony).

10 *Reply Testimony of Marie Y. Fontenot on Behalf of the California Community Choice Association* (September 10, 2021), p. 5.

assign these late-stage procurement requirements to the IOUs using CAM for the duration of the emergency.[11]

In its Opening Testimony, the California Independent System Operator ("CAISO") submitted two proposals that would materially change RA requirements for LSEs in 2022 and 2023. CAISO proposes to increase the Planning Reserve Margin ("PRM") from 15% to 17.5% to account for forced outages and the increased potential for extreme weather events.[12] CAISO also proposes a new system RA requirement based on the net peak demand at 8:00 p.m. for June through October. This new requirement would be in addition to the current system RA requirement based on the gross monthly peak and would apply to all months starting in 2023.[13]

The above-mentioned, or any other late-stage RA program procurement requirement changes, should be assigned to the IOUs using CAM for the duration of the emergency following the precedent set in D.21-03-056. This approach presents the most efficient and cost-effective means to secure RA-eligible capacity to meet the emergency period's reliability targets given the demonstrated emergency situation, the short timeframe in which to procure existing or incremental RA-eligible resources, and the already constrained RA market. MCE is concerned that assigning late-stage RA-eligible procurement to all LSEs will unnecessarily spike RA prices because of the number of LSEs forced to chase limited existing capacity on a compressed timeframe. Additionally, as the California Community Choice Association ("CalCCA") indicates in its Reply Testimony, many parties agree that despite best efforts, there are limitations to the amount of new

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[11] D.21-03-056, *Decision Directing Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022*, issued March 26, 2021 in Rulemaking ("R.") 20-11-003, at Ordering Paragraph ("OP") 14.

[12] *Opening Testimony of the California Independent System Operator Corporation* ("CAISO") (September 1, 2021), p. 12.

[13] *Id.* at 9.

capacity that can be secured by Summer 2022 to meet increased RA requirements.[14] If addressed in this proceeding, the Commission should direct the IOUs to take on any late-stage RA program changes during this emergency period, since doing so limits market disruption and best ensures that any available emergency RA-eligible capacity is acquired and costs are equitably allocated to all LSEs.

B. IF THE COMMISSION DOES NOT ADOPT A CAM APPROACH, THE COMMISSION SHOULD CONSIDER IMPOSING PENALTIES FOR LSES THAT FALL SHORT OF THE REVISED COMPLIANCE REQUIREMENT.

Not adopting a CAM approach to late-stage emergency procurement presents cost-shifting concerns and facilitates leaning among LSEs—whereby one LSE informally relies on other LSEs to support grid reliability without paying for the benefit— particularly if penalties are not assessed for deficient LSEs. As such, if the Commission adopts late-stage RA program changes that apply to all LSEs, the Commission should consider penalties for LSEs that fall short of the revised compliance requirement. Given the severity of the emergency situation, relying on a "best efforts" approach is unlikely to incent compliance, and may not lead to necessary capacity procurements.

As stated above, directing increased RA program requirements at this late stage is expected to increase RA costs for LSEs. Those LSEs that pursue capacity at the higher prices to do their part to meet reliability needs would be disadvantaged relative to those that made the economic decision not to procure. Such an outcome would create higher RA costs for compliant LSEs, encourage leaning by other LSEs that did not procure additional capacity, and create a potential for additional shared costs on compliant LSEs if deficiencies trigger CAISO's Capacity

[14] *Reply Testimony of Marie Y. Fontenot on Behalf of the California Community Choice Association* (September 10, 2021), p. 4; *see also Direct Testimony of Southern California Edison Company-Phase 2* (September 1, 2021), p. 57.

Procurement Mechanism. To avoid this scenario and the complications that may come with increased penalties under emergency conditions, the Commission should, to the extent addressed in this rulemaking, utilize CAM for any emergency-related, late-stage changes to the RA program that would increase procurement requirements or otherwise change RA program compliance requirements.

III. DEMAND-SIDE ISSUES

A. THE COMMISSION SHOULD EMPOWER MCE AND OTHER CCAS TO MAXIMIZE UTILIZATION OF DEMAND RESPONSE TO SERVE THEIR CUSTOMERS' LOADS.

As LSEs, CCAs have a legal responsibility to procure generation because the governing board of a CCA bears the sole responsibility for generation procurement on behalf of its customers.[15] California law requires that an electrical provider "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[16] The Commission's energy efficiency ("EE") Policy Manual and the State of California Energy Action Plan similarly define EE and DR as procurement resources that should be utilized at the top of a provider's loading order, prior to acquiring renewable or conventional energy resources.[17] MCE therefore has a legal responsibility to exhaust DR as a resource prior to procuring additional generation.

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[15] Cal. Pub. Util. Code § 366.2(a)(5) ("A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute.")

[16] Cal. Pub. Util. Code § 454.5(b)(9)(C); *see also* State of California Energy Action Plan ("EAP") I, 2003, p. 4 (defining a loading order with energy efficiency as the primary resource) and EAP II, 2008 (continuing the State's loading order commitments) *accessible at* https://www.cpuc.ca.gov/industries-and-topics/natural-gas/energy-action-plans; and the Commission Energy Efficiency Policy Manual, Version 5, p. 1 (noting energy efficiency is a procurement resource and first in the loading order).

[17] Commission, Energy Efficiency Policy Manual, Version 6, April 2020 ("EE Policy Manual"), p. 1, *available at* https://www.cpuc.ca.gov/energyefficiency/.

It is critical that MCE and other CCAs are enabled to provide DR on equal footing with, and without interference by, the IOUs. This principle supports MCE's request to access ratepayer funding to expand its existing demand flexibility programs proposal in this proceeding, as detailed below. If only IOUs have access to ratepayer DR funding, they will be at a significant advantage in developing and deploying DR resources. Providing IOUs this advantage, especially when providing DR programming to CCA customers, means that CCAs will be frustrated in utilizing DR to satisfy their own load obligations.

Allowing IOUs this advantage also makes little sense considering that IOUs, all else being equal, have a financial incentive to see loads grow in CCA territories. IOUs have a capital bias whereby they can earn a rate of return on any distribution capital infrastructure investments that would come with increased customer loads. They hence do not have an inherent interest in supporting customer programs that reduce, manage or curtail load. In contrast, CCAs do not make such capital investments, but instead strive to reduce load obligations and related greenhouse gasses.

For the foregoing reasons, CCAs must be able to fully leverage DR programming in a way that is non-discriminatory and that empowers them to shape their own load obligations. As recognized by California law and Commission policy, DR is a foundational tool to achieving this critical objective. CCAs must be able to fully unlock DR resources in the near term to meet the goals of the Emergency Proclamation.

B. THE COMMISSION SHOULD AUTHORIZE FUNDING TO LEVERAGE THREE MCE PROGRAMS THAT WILL IMPROVE GRID RELIABILITY.

MCE has already developed three demand flexibility programs that the Commission can leverage to quickly— and cost-effectively— achieve improved grid reliability in the summers of 2022 and 2023. All of MCE's programs are designed to align customer load shapes with grid needs, to reduce demand during times of grid stress, and stand ready to provide immediate capacity benefits.

First, the *Peak FLEXmarket* program is a new DR program that MCE launched on June 1, 2021 that is uniquely capable of achieving peak demand reduction at scale.[18] The *Peak FLEXmarket* can generate impacts from new demand flexibility providers and projects while minimizing risk to ratepayer funding and improving upon the measurement and verification ("M&V") of demand flexibility resources.[19] Second, MCE developed an *Energy Storage Program* that provides incentives to customers with solar PV to install energy storage systems ("ESS") in exchange for allowing MCE to control the charge and discharge of the customers' ESS, primarily for reducing peak loads.[20] MCE's third program is an Electric Vehicle ("EV") automated load management ("ALM")—*MCEv Sync.* This program is poised to deliver regular load shifting away from the 4 PM – 9 PM peak and to align as much EV charging as possible with high-solar daytime hours.[21]

The following table ("Table 1") outlines the peak demand reduction potential for each of MCE's program proposals for 2022 and 2023, and the associated budget request to scale the programs accordingly:

[18] MCE Phase 2 Testimony, p. 1-3:7-8.
[19] *Id.* at 1-3:9-10.
[20] *Id.* at 2-19:7-9.
[21] *Id.* at 2-31:20-21.

<u>Table 1</u>: Peak Demand Reduction Potential of MCE Program Proposals

	Peak Demand Reduction Potential (MW)		**Budget Request ($)**
	2022	**2023**	
Peak FLEXmarket	15	30	$11,560,000
Energy Storage Program	2	3.8	$4,408,000
MCEv Sync	2.5	5	$1,776,000
TOTAL	**19.5**	**38.8**	**$17,744,000**

1. The Commission Should Fund $11,560,000 for MCE's *Peak FLEXmarket* Program.

The Emergency Proclamation recognizes the immediate impacts of climate change and finds that "California currently faces an additional projected energy supply shortage of up to 3,500 megawatts during afternoon-evening 'net-peak' period of high power demand on days where there are extreme weather conditions."[22] The Emergency Proclamation notes that the CAISO sought to procure additional resources but that sufficient resources were not available to make up for the projected shortfall for summer 2021. Therefore, it is necessary "to take immediate action to reduce the strain on the energy infrastructure," to minimize reductions in emissions, and to protect the health and safety of Californians.[23] As such, the Emergency Proclamation directs all state agencies "to act immediately to achieve energy stability."[24]

MCE's *Peak FLEXmarket* is a highly innovative program designed to incent behaviors and solutions that directly address the needs identified in the Emergency Proclamation by reducing

[22] Emergency Proclamation.
[23] *Id.*
[24] *Id.*

demand during summer peak periods.[25] As described in MCE's Opening Testimony, *PeakFLEXmarket* incents load reductions during summer peak periods in two ways: (1) daily load shifting out of the 4 PM - 9 PM time window, and (2) DR or event-based participation when CAISO day-ahead market prices reach a certain threshold.[26]

Funding MCE's *Peak FLEXmarket* program as requested has the following benefits: (1) the program is market-based and technology-agnostic, fostering broad program participation and a unique capacity to scale;[27] (2) the program is already launched and can deliver meaningful load reduction impacts by June 1, 2022;[28] (3) MCE has identified a funding source already allocated to MCE for the program;[29] (4) MCE has deep experience in administering innovative Commission-funded ratepayer energy programs;[30] (5) the program is designed to access new customers and integrate between different program offerings;[31] (6) there is minimal risk to ratepayer funding because most program payments are made on a performance basis;[32] and (7) the program deploys robust M&V processes, using CalTRACK 2.0 methods with comparison group adjustments.[33]

i. *Peak FLEXmarket* is an Innovative and Scalable Program.

MCE's *Peak FLEXmarket* is a market-driven, technology-agnostic program framework that pays resources based on a transparent and consistent price signal.[34] Customers and/or aggregators can participate under the *Peak FLEXmarket* with a behavioral DR offering, a device-enabled strategy (*e.g.*, batteries, smart thermostats, or electric vehicle chargers), or any other

[25] Summer peak periods are defined as 4 PM – 9 PM between June 1 and October 31.
[26] MCE Phase 2 Opening Testimony, p. 2-4:23-24.
[27] *Id.* at 2-9:3-11.
[28] *See id.* at 1-3:8.
[29] *See id.* at 1-3:22 – 1-4:1.
[30] *See id.* at 1-2:12-16.
[31] *Id.* at 2-3:18-22.
[32] *See id.* at 2-12:22-23.
[33] *Id.* at 2-10:15.
[34] *See id.* at 2-12:22-23.

solution that generates verifiable results.[35] This approach avoids prescriptive solutions for how load reduction should occur and allows MCE to incentivize a multitude of demand flexibility approaches, which can work collectively and collaboratively towards enhanced grid benefits. Nearly any demand flexibility provider who meets the program's rules and requirements can participate.[36] MCE is well aware of the fact that different customers need different solutions and opening the door to a diverse pool of solutions is the best way to serve them.[37]

This market-based, open and flexible program model also allows MCE to easily scale the program and to forecast a larger potential to achieve peak demand reduction than traditional DR programs. MCE forecasts that the program can accommodate 15 MW of peak demand reduction in the summer of 2022, and 30 MW of peak demand reduction by summer of 2023.[38]

MCE has already seen significant interest in the *Peak FLEXmarket* from vendors and aggregators across the EE and DR spectrum. Within the first three months of program operations, seven aggregators enrolled in the *Peak FLEXmarket*, and ten more are actively engaging.[39] Four aggregators have submitted their first enrollments, with 1,465 meters assessed for eligibility, and 304 meters being actively tracked within aggregator portfolios.[40] This industry interest and support is also reflected in the Joint Parties' Reply Testimony in the instant proceeding. The Joint Parties, who represent a broad group of EE and DR providers, agree that MCE's *Peak FLEXmarket*

35 *Id.* at 2-9:3-11.
36 *See id.* at 2-9:13-19.
37 *See id.* at 2-9:3-11.
38 *Id.* at 2-15: 22-23
39 *Id.* at 2-6:8-10.
40 *Id.* at 2-6:8-11.

program is "highly innovative in several aspects" and recommend that the Commission approve MCE's *Peak FLEXmarket* program and proposed funding.[41]

ii. *Peak FLEXmarket* Can Achieve Meaningful Demand Reductions by June 1, 2022.

One of the biggest challenges in addressing the Emergency Proclamation is to identify programmatic approaches that can be designed, developed, launched, *and have a meaningful impact* by summer 2022. Fortunately, MCE is uniquely positioned to meaningfully reduce demand in this tight timeframe, given that it launched the *Peak FLEXmarket* in June of 2021 using its own ratepayer funds and the program is well positioned to scale up.[42]

There are often challenges to launching new demands-side programs. It can take program administrators ("PAs") 2-3 years to develop new ratepayer-funded EE or other DER programs.[43] Although program proposals made by other parties in this Proceeding have merit, MCE cautions against expecting demand reductions by Summer 2022 from programs that are not yet in the implementation stage. New program proposals must still go through the full program design, development and launch process and are unlikely to achieve peak demand reductions in the immediate time frame contemplated in the Emergency Proclamation.

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41 *See Phase 2 Reply Prepared Testimony of the Joint Parties (California Efficiency + Demand Management Council, ecobee inc., Leapfrog Power, Inc., and Oracle)* (September 10, 2021), p.17:1-2 (hereafter Joint Parties Phase 2 Reply Testimony).

42 *See* MCE Phase 2 Opening Testimony, p. 2-6:7-11.

43 *See, e.g.*, D.18-06-027, *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*, issued June 22, 2018 in R.14-07-002, OP 13-16 (directing IOUs create the DAC-Green Tariff and Community Solar ("CSGT") programs); Resolution E-4999, pp. 62-69, issued June 3, 2019 (approving, subject to modifications, IOUs' proposed DAC-GT and CSGT program implementation plans); IOU program implementation followed thereafter in 2020 (*see* DAC program and Request for Offers (RFO) timeline), accessible at https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/disadvantaged-communities.page?WT.mc_id=Vanity_dacrfo.

The *Peak FLEXmarket,* on the other hand, has already launched and is steadily growing, and is therefore well positioned to achieve meaningful peak demand reductions in time for Summer 2022.

iii. MCE Already Has a Ratepayer Funding Source for the Program Allocated.

As outlined in MCE's Opening Testimony, MCE proposes to fund incremental *Peak FLEXmarket* expansion from "unrequested funds" that are already allocated to MCE under its current EE funding authorization.[44] "Unrequested funds" represent the difference between the funds approved in MCE's EE Business Plan and the total budget that MCE has requested to date in its EE Annual Budget Advice Letters ("ABALs").[45] At present, MCE has approximately $11.9 million available in unrequested funds, which would suffice to cover the full budget requested for the *Peak FLEXmarket* program.[46]

These ratepayer funds have already been earmarked for MCE's customer programs and present a unique opportunity to leverage funding the expansion of the *Peak FLEXmarket*. It is appropriate to use unrequested EE funds in this instance not only because of the emergency need to develop programs by summer 2022 but also because the *Peak FLEXmarket* program is a "sister program" to an existing EE program (the Commercial Energy Efficiency Market Program) and is able to integrate EE and DR neatly into one program offering.[47] The fact that the Commission does not need to authorize any additional funding for the *Peak FLEXmarket* is a distinct advantage to ratepayers and will facilitate rapid implementation.

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44 MCE Phase 2 Opening Testimony, p. 2-17:3-8
45 *Id.* at 2-17:3-6, n.29.
46 *Id.* at 2-17:6-8.
47 *See id.* at 2-1:13 – 2-2:17.

iv. MCE Has Deep Experience in Administering Innovative Ratepayer Energy Programs.

MCE's demonstrated experience as a program partner to the Commission in administering innovative customer programs increases the likelihood of program success. Commission policies should recognize that CCAs are LSEs with an important role to play in fostering DR program expansion and customer participation, and that they are capable partners in doing so.[48]

MCE has extensive experience running customer programs that span the entire breadth of DERs, from EE and energy storage, to DR and transportation electrification ("TE").[49] In 2013, MCE became the first CCA to serve as a PA of ratepayer-funded EE programs.[50] Since 2013, MCE has deployed $36.2M in funding for general EE programs approved by the Commission.[51] Further,

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48 *See, e.g.*, D.12-12-036, *Decision Adopting a Code of Conduct and Enforcement Mechanisms Related to Utility Interactions with [CCAs], Pursuant to Senate Bill* 790, p. 6, issued December 28, 2012 in R.12-02-009 (recognizing that CCAs should have "the opportunity to compete on a fair and equal basis with other [LSEs]," and the need "to prevent utilities from using their position or market power to gain unfair advantages."); *id.* ("Unfair practices by any market participant, and particularly one with market power, may result in a reduction in customer choices, contrary to the public interest."); *id.* at Findings of Fact 4 & 5; D.16-09-056, *Decision Adopting Guidance for Future Demand Response Portfolios and Modifying Decision 14-12-024*, p. 52, issued October 5, 2016 in R.13-09-011 ("Utilities and third-party providers should fairly compete on a level playing field to vie for customers to enroll in their demand response programs."); *id.* at 56 ("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...Furthermore, our principle of consumer choice dovetails with this principle. We plan to continue offering a broad array of demand response options to customers, including the option of either the Utilities or third parties providing these services.").

49 MCE Phase 2 Opening Testimony, p. 1-2:10-12.

50 *Id.* at 1-2:12-13.

51 *See* Application ("A.") 12-07-001, *et. al.*, D.12-11-015, *Decision Approving 2013-2014 Energy Efficiency Programs and Budgets* (issued November 15, 2021); R.13-11-005, D.14-10-046 and supplemental budget approved in AL11-E-A, *Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Programs and Budgets (Concludes Phase I of R.13-11-005)* (issued October 24, 2014); R.13-11-005, D.16-05-004, *Decision Granting Marin Clean Energy's Petition to Modify Decision 14-10-046* (issued May 20, 2016); A.17-01-013, *et. al.*, D.18-05-041, *Decision Addressing Energy Efficiency Business Plans* (issued June 5, 2018).

MCE is also the only CCA program administrator that the Commission has authorized to administer Energy Savings Assistance ("ESA") programs.[52]

Since 2017, MCE has expanded its DER program portfolio, which now includes initiatives focused on low-income solar projects, energy storage, DR and TE.[53] In addition to these self-funded DER programs, MCE administers additional ratepayer-funded programs approved by the Commission. For example, MCE recently launched a community solar program for low-income customers in disadvantaged communities ("DACs"), the DAC Green Tariff ("DAC-GT") program.[54] MCE launched this program less than five months after the Commission approved its Implementation Advice Letter,[55] again exemplifying MCE's ability to launch new and innovative programs on an accelerated time frame.

As demonstrated by its program administration experience, MCE is a nimble organization capable of launching new and innovative programs with relative speed. Furthermore, MCE is a local agency that uniquely understands its customers' needs, which means that MCE can quickly tailor DR programs to scale customer engagement and maximize load impact.

v. *Peak FLEXmarket* Is Designed to Access New Customers and Integrate Between Different Program Offerings.

The *Peak FLEXmarket* program is uniquely positioned to identify and recruit *new* customers that traditionally may have not been interested - or aware of - DR program opportunities. The *Peak FLEXmarket* operates in parallel to, and complements, MCE's Commercial Energy

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[52] *See* A.14-11-007, *et. al.*, D.16-11-022, *Decision on Large Investor-Owned Utilities' California Alternate Rates for Energy (CARE) and Energy Savings Assistance (ESA) Program Applications* (issued November 21, 2016).

[53] *See* MCE Phase 2 Opening Testimony, p. 1-2:13-16.

[54] Pursuant to D.18-06-027, CCAs were granted the authority to administer the ratepayer-funded DAC Green Tariff and Community Solar Green Tariff alongside the IOU program administrators.

[55] The final Resolution (Resolution E-5124) approving MCE's Implementation AL (MCE 42-E-A-B) was approved by the Commission on April 15, 2021. MCE launched the DAC-GT program on September 1, 2021.

Efficiency Market program through the use of the same platform, and the opportunity for participating aggregators to deliver both EE and DR projects *together*.[56] One of the program's most promising attributes is that it is drawing interest from aggregators and customers who have never participated in DR programs or incorporated the value of demand flexibility into their projects, although the program has also seen participation from more traditional DR providers.[57] Through closer integration between MCE's EE and DR programs, the *Peak FLEXmarket* program can demonstrate the value of demand flexibility to all of MCE's program participants.

vi. ***PeakFLEXmarket* Minimizes Risk Through a Pay-for-Performance Model.**

There is minimal risk to funding the *Peak FLEXmarket* program because most program payments are based on performance.[58] Additionally, by offering a payment for energy reductions that values a range of resources equally, the *Peak FLEXmarket* ensures that incentives flow to projects and providers that generate verifiable impacts. It allows for different behind-the-meter ("BTM") solutions to work together in a coordinated way - not rewarding a specific product or technology - but utilizing any technology or action that generates results.[59] Simply put, *Peak FLEXmarket* is a pay-for-performance program, and the vast majority of program funding would only be spent on delivered benefits that align with the goals of the Emergency Proclamation.[60]

vii. ***Peak FLEXmarket* Deploys Robust M&V Processes, Using CalTRACK 2.0 Methods Paired with Comparison Group Adjustments.**

Lastly, the *Peak FLEXmarket* utilizes innovative M&V methods that demonstrate a substantial improvement over commonly used DR baseline methodologies, which may undervalue

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56 MCE Phase 2 Opening Testimony, p. 2-2:13-17.
57 *Id.* at 2-3:18-22.
58 *See id.* at 2-6:12 – 2-8:10 (describing the program's performance and compensation structure).
59 *Id.* at 2-9:3-11.
60 *See id.* at 2-13:3-4.

DR impacts, inhibit load shifting, and discourage deeper engagement and load reduction from customers and providers.[61] Within the *Peak FLEXmarket*, energy impacts are quantified through the open-source CalTRACK 2.0 methods and are further refined through Recurve's GRIDmeter comparison group adjustments.[62] These methods were developed with broad stakeholder input, and are already in use in EE programs. While offering improvements in the measurement of event-driven DR, they are mostly critical for being able to measure and reward both daily load shifting and event-driven DR together. In an increasingly complex DER environment where a single household may have an ESS, a SCT, and an EV, it is critical that programs continue to innovate and expand on current M&V practices to accurately assess impacts based on actual customer meter data.

As noted above, the Joint Parties agree that MCE's *Peak FLEXmarket* program is "highly innovative in several aspects", and specifically highlight the program's M&V methods.[63] As the Joint Parties note, the Commission can leverage the *Peak FLEXmarket* "to test these [measurement and verification methods] on a broader level and assess their accuracy relative to the current DR baseline."[64]

For all of the foregoing reasons, MCE respectfully requests that the Commission authorize $11,560,000 in program funding to effectuate growth of the *Peak FLEXmarket* and to achieve

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61 *See id.* at 2-11:3-6 (citing Marc Pare, Mariano Teehan, Stephen Suffian, Joe Glass, Adam Scheer, McGee Young & Matt Golden, "Applying Energy Differential Privacy to Enable Measurement of the OhmConnect Virtual Power Plant: A study of Demand Response during the California August 2020 blackouts" (December 2020), *available at* https://assets.website-files.com/5cb0a177570549b5f11b9550/6050a2a48c39eb09319c9382_Quantifying%20The%20OhmConnect%20Virtual%20Power%20Plant%20During%20the%20California%20Blackouts%20(1).pdf.

62 *Id.* at 2-10:15-18.

63 Joint Parties Phase 2 Reply Testimony, *Reply Prepared Testimony of Joint Demand Response Parties (CPower and Enel X North America, Inc.)* (September 10, 2021), p. 16:18-21 (hereafter "Joint DR Parties Phase 2 Reply Testimony").

64 Joint DR Parties Phase 2 Reply Testimony, p. 16:25-29.

meaningful, long-term and sustainable peak demand reduction.[65] As other parties recognize, MCE's *Peak FLEXmarket* presents the Commission with a "lower hanging fruit" opportunity to expand existing DR programs with additional funding.[66]

2. The Commission Should Authorize $4,408,000 for MCE's *Energy Storage Program*.

The Commission should approve MCE's request for $4,408,000 to expand its *Energy Storage Program* in order to deliver peak demand reductions that can be achieved in the summers of 2022 and 2023. The Emergency Proclamation directs the Commission to work with LSEs on accelerating plans for "storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day."[67] Furthermore, the Amended Scoping Ruling specifically identifies virtual power plants ("VPPs") or DER export as resources that are capable of reducing demand, and thus MCE's request is directly within the scope of this proceeding.[68] The Commission should act now to accelerate the impact of MCE's *Energy Storage Program* to not only achieve peak demand reductions in the summers of 2022 and 2023 but also to increase the availability of carbon-free energy at all times of the day.

MCE launched its *Energy Storage Program* in July of 2020 to achieve daily load reductions during the afternoon/ evening peak period and to offer customer resiliency for public safety power shutoff ("PSPS") events.[69] The program works by compensating participating solar customers who install new ESS (both residential and non-residential) in exchange for allowing MCE to directly monitor and control their system using a Distributed Energy Resources Management System

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65 *See* MCE Phase 2 Opening Testimony, pp. 2-12:18 – 2-14:22 for a detailed discussion of MCE's proposed program budget.

66 *See*, e.*g.*, *Reply Testimony of Jin Noh on behalf of the California Energy Storage Alliance* (September 10, 2021), p. 20:11-18 (hereafter "CESA Phase 2 Reply Testimony").

67 Emergency Proclamation, Order 2 at 3.

68 Amended Scoping Ruling, p. 5.

69 MCE Phase 2 Opening Testimony, p. 2-20:9-10

("DERMS") software platform.[70] Using this platform, MCE can control participating customers' ESS to align charging and discharging behavior with grid needs and to reduce demand during times of grid stress.[71] In exchange for participating in this program and authorizing MCE's control, customers receive up-front, monthly participation, and performance-based incentives to lower the cost of their ESS.[72]

As mentioned above, MCE has a long-standing history and extensive experience running ratepayer-funded energy programs that span the entire breadth of DERs. Funding MCE's *Energy Storage Program,* as proposed, will provide the following benefits: (1) the program can achieve reliable peak demand reduction and increases grid reliability; (2) MCE can leverage the existing program pipeline to achieve peak demand reductions by June 1, 2022; (3) the program recruits customers into DR programs that have traditionally not engaged in such programs, including low-income and vulnerable customers; and (4) the program tracks granular data that is used to verify results and continually improve performance.

i. The *Energy Storage Program* Can Achieve Reliable Peak Reductions and Improve Grid Reliability.

MCE's *Energy Storage Program* can achieve the peak demand reductions contemplated in the Emergency Proclamation. MCE forecasts a peak demand reduction of 2.05 MW by June 1, 2022 (based on an installed capacity of 13.4 MWh or 3.36 MW) and a peak demand reduction of 3.8 MW by June 1, 2023 (based on an installed capacity of 25 MWh or 6.27 MW).[73]

MCE can achieve peak demand reductions through its *Energy Storage Program* in two ways. First, in its current operation, the program achieves daily load shifts during the evening peak

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70 *Id.* at 2-19:18-20.
71 *Id.* at 2-19:7-11.
72 *Id.* at 2-20:2-3.
73 *Id.* at 2-28:18-20.

period throughout the entire year by automatically charging participating customers' ESS from solar PV, during off-peak hours and discharging these resources each day during the peak hours of 4pm to 9pm.[74] Second, with additional funding, MCE could expand the *Energy Storage Program* to develop a use case for discharge during CAISO day-ahead and day-of events when triggered by the Alert, Warning and Emergency ("AWE") process.[75]

Hence, MCE's *Energy Storage Program* is directly aligned with the State's goal of decreasing peak period energy demand, and is designed to achieve this goal on a consistent, long-term basis. Additionally, if the Commission moves to allow exports from the ESS, particularly for systems larger than 10 kW, MCE's *Energy Storage Program* would be positioned to achieve even greater peak demand reductions, and on a faster timeline.[76]

MCE's *Energy Storage Program* stands out from many other energy storage programs because MCE has direct control over the ESS, which ensures that grid capacity needs are met. Unlike a for-profit developer, who may have other goals to generate revenue or meet performance guarantee obligations under contracts with their customers, MCE's DERMS platform can prioritize peak load reduction when the grid needs them. MCE has put significant time, effort, and money into developing the platform, which provides MCE better ability to control the ESS than programs that rely on LSEs to contract with several providers to coordinate ESS deployment.

For all the reasons mentioned above, MCE's *Energy Storage Program* is well designed to achieve reliable peak demand reduction and improve grid reliability in the summers of 2022 and 2023.

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[74] *Id.* at 2-19:21-22.
[75] *Id.* at 2-22:17-20.
[76] *See id.* at 2-28:23-24.

ii. MCE's Existing *Energy Storage Program* Can Deliver Impacts by Summer 2022.

Similar to the *Peak FLEXmarket* program, the *Energy Storage Program* has the great advantage of already being up-and-running. The first ESS installation under the program was completed in late 2020 and MCE expects to begin dispatching systems for daily peak load shifting in the 4th quarter of 2021.[77] MCE is confident that the *Energy Storage Program* can deliver peak demand reductions by June 1, 2022 as MCE proposes to leverage existing customers, who are already going through the ESS installation process or who are in the pipeline for installations, to achieve near-term peak demand reductions by next summer.

MCE strongly cautions the Commission against relying on speculative demand reductions for summer of 2022 from *new* programs that are not yet in the implementation stage. The Emergency Proclamation calls for immediate action,[78] but such immediate action is not possible for programs that have not yet launched. This is particularly true for any device-enabled program, and even more so for new energy storage program proposals. MCE has already experienced extended timelines for ESS permitting, installation and interconnection under MCE's *Energy Storage Program*.[79] Hence, it is unlikely that any ESS program proposal that is not yet in the implementation phase could achieve peak demand reductions by the summer of 2022. The Commission should prioritize expanding funding for MCE's *Energy Storage Program* and other programs that are already in the implementation phase.

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77 *Id.* at 2-27:14-17.

78 Emergency Proclamation, Ordering Paragraph 2, p. 3.

79 *See* MCE Phase 2 Opening Testimony at 2-30: 19-2.

iii. The *Energy Storage Program* Recruits Customers into DR Programs That Have Typically Not Engaged in Such Programs, Including Low-Income and Vulnerable Customers.

As described above, MCE's *Energy Storage Program* was originally developed with the goal of increasing customers' resiliency in response to PSPS events. Accordingly, the large majority of customers who are currently participating in the program are installing ESS at their homes and businesses to be better prepared for wildfire and PSPS-related outages. Those customers are not necessarily aware of opportunities to also leverage their ESS to participate in a DR program. However, if the Commission grants MCE's funding request in this proceeding, MCE can leverage these installations to also achieve near-term peak demand reductions.

Furthermore, MCE's program provides increased incentives and has a participation goal of 50% for low-income or other vulnerable customer categories.[80] This is a customer group that has not traditionally participated in DR programs.[81] Encouraging the participation of low-income, DAC and other vulnerable customer groups in ratepayer funded programs has been a consistent goal of the Commission across the various program-related proceedings.[82] Expanding MCE's *Energy Storage Program* will further the Commission's efforts in this endeavor.

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80 *Id.* at 2-23:8-9; *see also id.* at n.33 (defining "vulnerable customer" to include those living in DACs, designated Low-Income Communities, or those with a medical need, living in a Tier 2 or 3 High Fire Threat District, or who have experienced two or more PSPS events. This customer base also includes government and nonprofit organizations that provide essential services to vulnerable communities.).

81 *See* MCE Phase 2 Opening Testimony, p. 3-8:8-10 (noting that low-income multi-family and moderate-income single-family customers tend to be hard-to-reach customer segments).

82 *See, e.g.*, D.18-06-027 (creating the DAC-GT and CS-GT programs); Environmental and Social Justice Action Plan, February 21, 2019 (establishing an action plan to "advanc[e] decisions and programs" that remove some of the "high[] barriers" certain customer segments face in accessing safe and affordable utility service) *accessible at*: https://www.cpuc.ca.gov/news-and-updates/newsroom/environmental-and-social-justice-action-plan); and D.19-09-027 (establishing the Equity Resiliency Budget under the Self-Generation Incentive Program).

MCE's *Energy Storage Program* represents a clear opportunity for the Commission to engage a broader customer base to deliver peak demand reduction from previously untapped resources.

iv. The *Energy Storage Program* Collects Granular Data That Is Used to Verify Results and Continually Improve Performance.

The *Energy Storage Program* collects complete performance data for all ESS for all participants.[83] MCE will thus have a precise record of all kWh charged and discharged from each individual system, recorded in 5-minute intervals.[84] The program does not rely on customer smart meter data, and does not require the use of baselines to determine performance. Instead, MCE's DERMS system tracks real time individual customer ESS performance data and aggregated VPP performance data.[85] The DERMS software also uses "big data analysis" and machine learning to continually re-optimize dispatches to maximize performance of the VPP, based on this data.[86]

Having access to this wealth of performance data is beneficial for two reasons. First, program results are reliable and verifiable because participants are only compensated based on metered performance for individual ESS. Second, MCE seeks stakeholder review and programmatic feedback on the program's performance data, thereby creating a learning opportunity for MCE, the Commission, and stakeholders.[87]

For all of the foregoing reasons, MCE respectfully requests that the Commission authorize $4,408,000 of ratepayer funds for MCE to scale its *Energy Storage Program* to achieve additional peak demand reduction during the summers of 2022 and 2023, consistent with the needs identified in the Emergency Proclamation. MCE requests that the Commission authorize MCE access to the

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83 MCE Phase 2 Opening Testimony, p. 2-21:12-16.
84 *Id.* at 2-21:14-15.
85 *Id.* at 2-23: 12-15.
86 *See id.* at 2-21:20-24.
87 *See id.* at 2-21:7-9.

same ratepayer-funds that it intends to allocate to other program proposals that may be authorized under Phase 2 of this Rulemaking.

3. The Commission Should Authorize $1,761,000 for The *MCEv Sync* Program.

The Commission should authorize $1,761,000 funding to leverage and quickly scale *MCEv Sync*.[88] The Amended Scoping Ruling identifies EV infrastructure as a possible DR resource or load management tool that should be considered or expanded in this Rulemaking.[89] *MCEv Sync* is one such program, as it allows MCE to control EV charging behaviors of enrolled customers to reduce peak demand and improve grid reliability, consistent with the goals of the Emergency Proclamation and this Rulemaking.

As mentioned above, MCE has a long-standing history and extensive experience running ratepayer-funded energy programs that span the entire breadth of DERs, including TE initiatives. Funding *MCEv Sync* as requested has the following benefits: (1) proven ability to achieve peak demand reductions; (2) potential to achieve meaningful demand reductions with EVs located in MCE's service area; and (3) rapid implementation by Summer 2022 due to the fact that the program is fully designed and developed.

i. The *MCEv Sync* Program Model Has a Proven Ability to Achieve Peak Demand Reductions.

As with MCE's *Peak FLEXmarket* and *Energy Storage Program*, peak demand reductions under the *MCEv Sync* program can be achieved in two ways. First, the primary aim of *MCEv Sync* is to deliver regular load shifting away from the 4 PM – 9 PM peak and to align as much EV charging as possible with high-solar daytime production hours.[90] Second, if the Commission

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88 *See* MCE Phase 2 Opening Testimony, p. 2-37:8 for full program budget proposal.
89 Amended Scoping Ruling, p. 5.
90 *Id.* at 2-31:20-21.

authorizes additional funding, MCE would incorporate a secondary use case under the program to deliver additional peak demand reduction during DR events called by CAISO.[91]

MCE is confident that if the Commission approves MCE's funding proposed herein, the *MCEv Sync* program will achieve an estimated 2.5 MW of peak demand reduction by June 1, 2022 and an estimated 5 MW of peak demand reduction by June 1, 2023. These estimates are based on an expected enrollment of 2,500 EVs by summer 2022 and 5,000 EVs by summer 2023, with each participating EV delivering approximately 1kW of average peak demand reduction.[92]

These claims can be substantiated because MCE's program partner, ev.energy, has already shown its capability of reducing demand at peak hours at a level of approximately 1.4kW per vehicle in program applications in other parts of the country.[93] In Texas, ev.energy built a VPP of EVs that has seen demonstrable success in curtailing EV load during the 7 PM - 10 PM peak period as shown in the figure below.[94]

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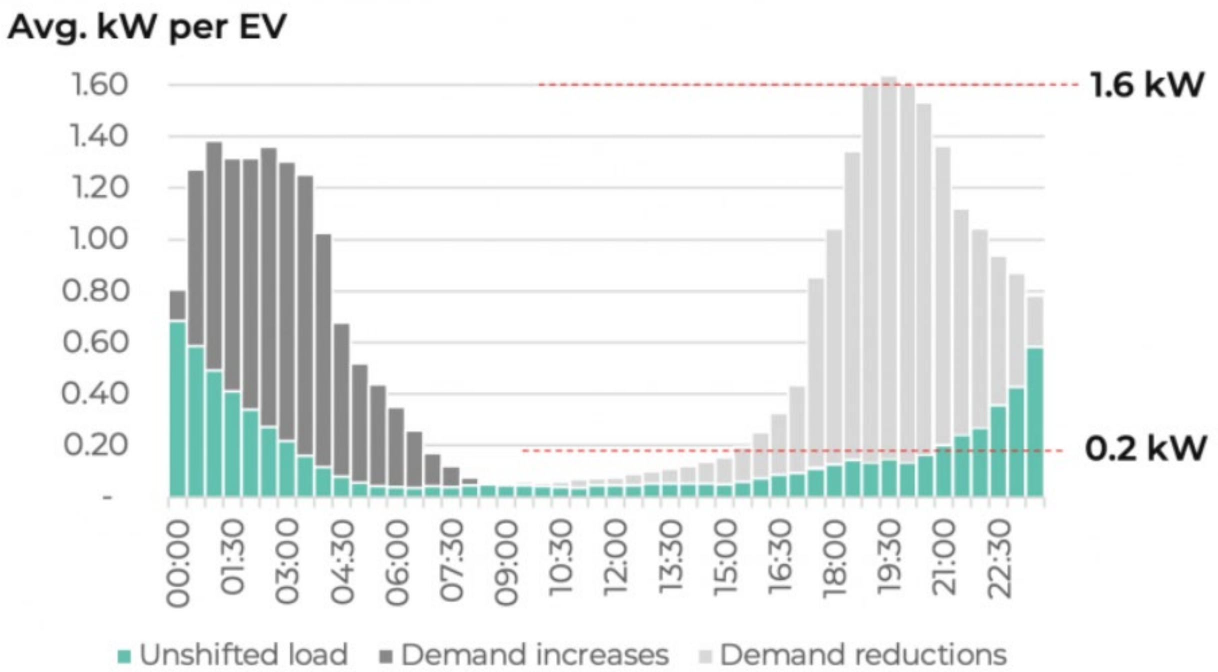
[91] *Id.* at 2-32:13-14.
[92] *Id.* at 2-40:7-10.
[93] *See* MCE Phase 2 Opening Testimony, p. 2-33:1-4.
[94] *Id.* at 2-33:3-4.

<u>Figure 1</u>. ev.energy Peak Load Shaving Experience in Texas



As described by ev.energy, the light grey bars represent scheduled EV charging that was shifted outside of Electric Reliability Council of Texas ("ERCOT") Emergency Response Service event windows, to the dark grey bars. Green bars on the bottom represent unshifted load due to customers opting out of the event to continue charging. On average, ev.energy is able to curtail 1.4 kW of load per vehicle in Texas.[95]

ii. There is Potential to Achieve Meaningful Demand Reductions with EVs Located in MCE's Service Area.

There is potential to achieve meaningful peak demand reduction through the managed charging of EVs in MCE's service area. MCE's service area has a relatively high concentration of EVs compared to state averages— approximately 43,389 EVs are currently registered in MCE's

95 *Id.* at 2-32:22-23 and p.2-33:1-4

service area which covers Marin, Napa, Solano and Contra Costa counties.[96] On the other hand, nearly 80% of MCE's residential customers are still enrolled in flat rates (*e.g.,* the residential base rate E1). These customers are not financially incentivized to avoid charging during the peak demand window.[97] Furthermore, the majority of EV owners may not be aware of the fact that they should not charge their EVs when they come home from work but instead wait until later at night. For these reasons, MCE believes that an expanded EV ALM program will have a meaningful impact in reducing peak demand in the summers of 2022 and 2023.

iii. The *MCEv Sync* Program Is Fully Designed And Developed And Can Deliver Impacts in Summer 2022.

As with MCE's other program proposals, MCE has already designed and developed the *MCEv Sync* programs, which will launch by the end of September.[98] Hence, MCE can expand upon an existing pipeline of participating customers to achieve peak demand reductions by June 1, 2022. The fact that the program has already been designed and developed also means that the vast majority of program startup costs have already been paid by MCE through its own ratepayer generation revenues. MCE only requests targeted additional funding necessary to grow the program participation numbers and to add a secondary use case for event-based demand reductions.[99] Hence, the program is a cost-effective, complete and scalable proposal, which the Commission should approve.

For all of the foregoing reasons, MCE respectfully requests that the Commission authorize $1,776,000 of ratepayer funds for MCE to grow an already designed and innovative program—

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96 California Energy Commission, *Zero Emission Vehicle and Infrastructure Statistics*, *accessible at*: https://www.energy.ca.gov/data-reports/energy-insights/zero-emission-vehicle-and-charger-statistics (last accessed September 20, 2021).

97 MCE Phase 2 Opening Testimony, p. 2-33: 5-7.

98 *Id.* at 2-32:3.

99 *Id.* at 2-37:11-14.

MCEv Sync— that can deliver increased peak demand reduction as soon as June 2022. MCE requests that the Commission authorize MCE access to the same ratepayer-funds that it intends to allocate to other program proposals that may be authorized under Phase 2 of this Rulemaking.

C. THE COMMISSION SHOULD REJECT ANY AUTO-ENROLLMENT OF UNBUNDLED CUSTOMERS INTO AN IOU DR PROGRAM.

The Commission should reject any proposals that would automatically enroll ("auto-enroll") unbundled customers into an IOU-administered DR program, including the Staff Concept Paper's proposal to auto-enroll all residential customers into the Emergency Load Reduction Program ("ELRP").[100] Auto-enrollment program designs are contrary to Commission policy and the goals of this Rulemaking, as elaborated below. Most notably, auto-enrollment designs should be rejected because they: (1) tilt the DR landscape towards IOU monopolization, contrary to longstanding Commission policy; (2) are unlikely to generate impacts; (3) inhibit market innovation; and (4) create implementation challenges that would impede growth of DR programs and likely cause customer confusion.[101]

1. Auto-enrollment Would Tilt the DR Landscape Towards IOU Monopolization, Contrary to Longstanding Commission Policy.

Because of the Commission's prohibition on dual participation under DR programs, auto-enrollment into IOU DR programs effectively blocks large subsets of MCE's customers from enrolling in new or alternate demand flexibility programming.[102] Decision ("D.") 16-09-036 established that "Utilities and third-party providers should fairly compete on a level playing field

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[100] Energy Division Staff Concept Paper, *Proposals for Summer 2022 and 2023 Reliability Enhancements*, August 16, 2021 (hereafter "Staff Concept Paper"), p. 5. Proposals of auto-enrolling residential customers were also made in the Phase 1 proposals submitted by PG&E and CEJA in Supplemental Testimony submitted by the parties in July of 2021.

[101] *See, e.g.*, CESA Phase 2 Reply Testimony, p. 21:16-20; *see also* SCE Phase 2 Direct Testimony, p. 4:11-5:16; MCE Phase 2 Opening Testimony, pp. 3-2:14 – 3-4:20.

[102] MCE Phase 2 Opening Testimony, p. 3-3:6-9.

to vie for customers to enroll in their demand response programs."[103] Additionally, the Commission determined in D.12-12-036 that CCAs must have "the opportunity to compete on a fair and equal basis with other load-serving entities."[104] This opportunity should also apply to CCA DR program administration, given its importance as a load-management tool, and CCAs' role as a LSE.[105]

MCE appreciates the Commission's commitment to maintaining a level playing field across DR providers, and notes that the Commission and stakeholders have made significant strides over the past decade to shift primary DR program administration from the IOUs to third-party demand response providers ("DRPs").[106] Allowing auto-enrollment into IOU DR programs would run contrary to these established policies by further entrenching IOU market power and denying CCA's the opportunity to administer DR programs "on a fair and equal basis with other load-serving entities."[107]

As described above, MCE has worked to develop innovative demand flexibility programs that are well-targeted towards MCE's customer-base and already show signs of significant customer engagement and peak demand reduction. MCE developed these programs on its own initiative and with its own ratepayer funding because these programs are critical load management tools. However, if the Commission adopts policies—such as auto-enrollment or siloed IOU funding—that tilt towards IOU monopolization of MCE's customer base, MCE will be unable to remain competitive with IOU DR program providers. As noted above, it is critical that as LSEs,

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103 *See* D.16-09-056, p. 52.
104 *See* D.12-12-036, p. 2
105 *See infra*, Section III.A (discussing the importance of prioritizing DR in the loading order and MCE's role as a LSE).
106 *See, e.g.*, D.16-09-056, D.17-10-017 (adopting competitive neutrality principles for DR program implementation).
107 *See* D.12-12-036, p. 2

CCAs are able to fully utilize DR to reduce procurement obligations.[108] Allowing IOU auto-enrollment of unbundled customers thwarts a CCA's ability to manage its own load.

2. Auto-enrollment Programs are Unlikely to Generate Meaningful Impacts.

MCE believes that auto-enrollment programs are unlikely to generate significant peak demand reduction impacts. This is especially true if customer notice is not required, as proposed in the Staff Concept paper.[109] However, the Emergency Proclamation directs all state agencies "to act immediately" to make up for the "projected energy supply shortage of up to 3,500 megawatts during the afternoon-evening 'net-peak' period of high power demand on days where there are extreme weather conditions."[110] The Emergency Proclamation also requests that the CPUC "exercise its powers to expedite Commission actions, to the maximum extent necessary to meet the purposes and directives of this proclamation, including by expanding and expediting approval of demand response programs . . . to ensure that California has a safe and reliability electricity supply through October 31, 2021, to reduce strain on the energy infrastructure . . ."[111] Compliance with this Emergency Proclamation requires *meaningful* demand reductions in a very short period of time.

DR programs can only be impactful and achieve the meaningful demand reductions necessary to respond to the Emergency Proclamation if customers are aware of, and engaged in, the program. The large majority of, if not all, program proposals for residential DR programs made to date consider some sort of customer control over DR participation and do not incorporate

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108 *See infra*, Section III.A (discussing the importance of prioritizing DR in the loading order and MCE's role as a LSE).

109 Staff Concept Paper, p. 5 ("All residential customers would be automatically enrolled in ELRP (except customers currently enrolled in supply-side DR programs). *There would be no required sign-up or acknowledgement process.*") (emphasis added).

110 Emergency Proclamation.

111 *Id.*

customer penalties. In the case of behavioral DR programs, it is obvious that demand reductions can only be achieved if the customer takes proactive action to reduce demand during times of high grid stress (*e.g.*, by not running the dishwasher). And even for device-enabled DR programs, residential customers usually have the option to override automatic participation signals (*e.g.*, a customer can lower the temperature on a smart control thermostat even if a control provider has increased the temperature due to a DR event). Hence, DR programs are only really impactful if customers are aware of the program and are "energy engaged."

3. Auto-enrollment Will Stifle Innovation in the DR Program Arena Overall.

MCE is concerned that auto-enrolling residential customers in DR programs will not only have little impact in achieving peak demand reduction and grid reliability goals, but will also stifle innovation in the DR program arena overall by foreclosing opportunities for customers to participate in higher impact and higher reward programs.[112]

As described in the program section above, MCE has already developed three innovative demand flexibility programs that have the potential to achieve meaningful peak demand reductions in the summers of 2022 and 2023. In particular, the *Peak FLEXmarket* program incorporates many highly innovative program design elements that better position it to achieve meaningful peak demand reductions than IOU auto-enroll programs. First, the market-based, technology agnostic, and simple program design is attractive to a wide array of DR providers and customers.[113] Second, the transparent and consistent price signal is a simple and valuable means for incenting customers to participate while not making the program overly complex and burdensome to participate in. Third, the program integrates demand reduction opportunities with other program opportunities

112 MCE Phase 2 Opening Testimony, pp. 3-4:14-18.
113 *See id.* at 2-9:3-11, 2-6:7-11.

(*i.e.,* it integrates DR offerings for customers participating in MCE's EE programs). This integration and coordination of various program initiatives greatly increases the likelihood of customers being "energy engaged" and to participate in event-based DR when the grid needs it the most. All these factors make MCE's program a higher impact and higher reward program offering than the auto-enroll IOU programs proposed to date.

4. Auto-enrollment Would Create Implementation Challenges That Would Impede Growth of DR Programs and Likely Cause Customer Confusion.

Several parties have highlighted on the record of this Rulemaking that auto-enrollment will likely cause customer confusion and possibly program disengagement altogether.[114] MCE agrees.[115] Furthermore, MCE cautions that "simply unenrolling" customers from the IOU auto-enrollment program to enroll them into another third-party or CCA DR program offering may not be as "simple" as envisioned by some parties.[116]

OhmConnect elaborated at length on this issue in its reply testimony submitted on the Pacifica Gas and Electric ("PG&E") and California Environmental Justice Alliance ("CEJA") residential program proposals that were submitted to the record of this proceeding in supplemental testimony in July 2021.[117] For example, OhmConnect states that its customer service team "spends thousands of hours helping potential customers navigate the IOU disenrollment process," and customers "[i]nevitably[] become frustrated and disenchanted with DR altogether."[118] As

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114 *See, e.g.*, *Phase I Reply Testimony of OhmConnect, Inc.* (July 21, 2021), pp. 3-9 (hereafter OhmConnect Phase I Reply Testimony); *Phase I Prepared Reply Testimony of San Diego Gas & Electric Company regarding Demand Response Proposals* (July 21, 2021), pp. 2-3 (expressing concerns with the opt-model); MCE Phase 2 Opening Testimony, p. 3-3:1-5; 3-4: 3-14; CESA Phase 2 Reply Testimony, p. 21:16-20; *see also* SCE Phase 2 Direct Testimony, p. 4:11-5:16.

115 *See* MCE Phase 2 Opening Testimony p. 3-4: 3-14.

116 *See, e.g.*, PG&E Phase 2 Opening Testimony, p. 2-9:20-31; CEJA Opening Testimony, p. 4:22-26.

117 OhmConnect Phase I Reply Testimony, pp. 3-9.

118 OhmConnect Phase I Reply Testimony, p. 5:20-21.

OhmConnect points out, this process would be even more challenging if, as envisioned in the Staff Concept Paper, customers were not even aware that they had been enrolled in a DR program.[119] Due to these program implementation challenges and the potential for customer confusion and disengagement, the Commission should reject auto-enrollment provisions for DR programs.

In summary, the Commission should reject auto-enrollment for residential DR programs as it is not in the public interest, not consistent with Commission policy or the Emergency Proclamation, and can lead to customer disengagement.

D. THE COMMISSION SHOULD REQUIRE A STREAMLINED DATA-SHARING PROCESS FOR IOUs AND CCAs.

1. Customer Program Participation Data Access Issues are Within Scope.

The Commission should reject SDG&E's assertion that data sharing proposals are beyond the scope of this proceeding. The Amended Scoping Ruling is broadly scoped to consider "opportunities" and other considerations that may reduce peak demand and net peak demand hours in summer 2021,[120] and the August 11 *E-Mail Ruling of Administrative Law Judge Stevens* ("Email Ruling") expressly invites parties to "identify any new policy or modification to an existing policy that could reduce demand or increase supply at net peak (for example a rule, regulation, *etc.*).[121] Creating a streamlined avenue for DR providers— whether an IOU, a CCA or third party DRP— to share customer participation data in all DR programs (and other pertinent data that stakeholders may deem relevant) will facilitate customer enrollment in programs and thereby help to reduce

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[119] *Id.* at 6:7-9 ("If disenrollment is difficult with a group of customers that had proactively enrolled in a DR program, it will be infinitely more cumbersome with those who have been opted in without their knowledge.").

[120] Amended Scoping Ruling at 4, 5.

[121] August 11 Email Ruling, p. 2 (Proposal Guideline No. 2).

peak demand. Indeed, SDG&E even considers "that a comprehensive discussion of data-sharing could be fruitful."[122]

2. The Commission Should Direct the IOUs to Share Customer Participation Data on a Quarterly Basis.

The Commission should adopt a quarterly data-sharing requirement to ensure the consistent and reliable exchange of DR program enrollment data among IOUs, CCAs and other DRPs. The Emergency Proclamation underscores the urgency of the crisis facing California by ordering the Commission to "expedite Commission actions to the maximum extent necessary to meet the purposes and directives" of the Emergency Proclamation and to "expand expedite approval of demand response programs."[123] However, both CCAs and DRPs will be impaired in their abilities to administer DR programs without complete program participation data.

CCAs require DR program participation data in order to effectively and efficiently target customers. Without this data, CCAs are likely to spend significant time and effort contacting customers that may not be eligible for the CCA's DR programs, as they may already be enrolled in IOU DR programs.[124] This can also cause customer confusion and attrition since DR providers cannot quickly and reliably confirm eligibility. As stated in MCE's testimony, "[t]his is neither a good use of public funds, nor [is it] in alignment with the urgency" reflected in the Emergency Proclamation.[125]

Under existing practice, pertinent customer participation data is difficult to obtain, and even where some information is provided, it is inadequate or incomplete.[126] For example, PG&E's

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122 SDG&E Phase 2 Reply Testimony Regarding Demand-Side Actions to Reduce Peak and Net Peak Demand in 2022 and 2023, p. 11:4-11.

123 Emergency Proclamation, p. 10 para 13.

124 MCE Phase 2 Opening Testimony, p. 3-5:15-17.

125 *Id.* at 3-5: 17-18.

126 *See id.* at 3-5:9-15.

program data sharing is currently limited to its Rule 24 report, which includes only a fraction of customers who are enrolled in various IOU DR programs, pilots and initiatives.[127] In MCE's experience, PG&E has been unable (or unwilling) to share customer participation data on all DR programs on a voluntary basis, and cites a lack of direction from the Commission and concerns regarding customer data confidentiality.[128]

Specifically, the Commission should direct the IOUs to share customer participation data on a quarterly basis. This will allow for streamlined DR program development, customer enrollment, efficient implementation of targeted marketing, education and outreach campaigns, and will minimize customer confusion and prevent dual enrollment. Moreover, the Commission is clearly authorized to implement this data-sharing mandate under the broad scope of this Rulemaking, and there is precedent for this type of data sharing on a broader scale.[129]

Further, to the extent the Commission is concerned with protocols for sharing customer data with CCAs or believes that additional record discussion would be helpful, the Commission should require a stakeholder workshop within 30-days of a Commission decision on this Ruling to determine the proper data-sharing protocol.

E. THE COMMISSION SHOULD MAINTAIN ITS POLICY OF INCORPORATING SCT TECHNOLOGY AS A KEY TO INCREASED LOAD MANAGEMENT.

The Commission should reject the Staff Concept Paper proposals that would impose new limits on the use and funding of SCT due to their alleged "limited energy efficiency savings."[130] Specifically, the Staff Concept Paper proposes to (1) limit SCT installations to "hot zone

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127 *See id.* at 3-5:9-11.

128 MCE Phase 2 Opening Testimony, pp. 3-5:11-13.

129 *See id.* at 3-5:23 – 3-6:3 (explaining that nondisclosure agreements are already in place between CCAs and IOUs to "exchange customer data on a much broader scale than DR program participation reporting").

130 *See* Staff Concept Paper, pp. 9-16.

climates";[131] and (2) establish an "enrollment requirement" whereby SCT incentives must be paired with DR enrollment in ELRP or any other "supply-side DR programs offered by the IOUs or third-party DR Providers or other designated pilot programs offered by IOUs," without any mention or recognition of CCA providers.[132] This proposal omits CCAs from the enrollment criteria, and caps SCT installations in a shortsighted manner. SCTs remain an important tool for leveraging customer involvement and maximizing DR savings and should not be curtailed—particularly under a Rulemaking intended to urgently address demand shortfalls.

As CEJA notes, there is "…widespread agreement that a smart thermostat program would be an effective way to reduce demand" and "should not be limited to only hot climate zones and [] should be tied to enrolling customers in DR programs."[133] MCE also agrees with OhmConnect's observation that the Commission's "overarching objective should be to increase the uptake of load automating devices among customers enrolled in DR programs statewide."[134] MCE additionally points out that, consistent with the goals of this Rulemaking and the Emergency Proclamation, any Commission actions taken under this ruling should be additive to—and not reduce- the existing impacts of an EE Portfolio. To this end, the Commission should adopt an "all of the above" approach to SCTs.

MCE also notes that the climate is changing quickly and any currently designated "hot zone areas" may prove too limiting in time. For example, coastal areas that may not have historically qualified as a "target hot climate zone" are experiencing an increased number of warm

131 *Id.* at 13.
132 *Id.* at 15.
133 CEJA Phase 2 Reply Testimony, p. 9:10-13.
134 OhmConnect Phase 2 Reply Testimony, p. 6:18-20.

temperature days that are driving customers to install air conditioning in historically cooler places.[135]

Finally, while MCE agrees that it would be prudent to pair SCT technology with other demand reduction measures, MCE requests that the Commission include CCA program participation in the eligibility requirement for SCT installations in addition to IOU and third-party DRP programs.

SCTs offer customers an attractive entry point into EE and DR programs that can increase customer engagement and help convince a customer to undertake a more comprehensive project.[136] The Commission should not abandon this access point now.

IV. CONCLUSION

For the foregoing reasons, MCE respectfully urges the Commission to take the following actions:

On the supply side:

- Require that any late-stage RA program changes adopted on an emergency basis in this proceeding still follow the emergency process that the Commission adopted in Decision 21-03-056, and assign these late-stage procurement requirements to the IOUs using the CAM for the duration of the emergency.
- Impose penalties for RA deficiencies, if the Commission assigns late-stage RA program procurement requirements to all LSE.

On the demand side:

- Empower MCE and other CCAs to maximize DR utilization to serve their customers' loads.

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135 *See* MCE Phase 2 Testimony, p. 3-7:8-11.

136 MCE Phase 2 Opening Testimony, p. 3-8:13-14.

- Authorize ratepayer funding to leverage three MCE programs that present a cost-effective, low-hanging fruit opportunity to achieve peak and net peak demand reductions in time for summers 2022 and 2023, as shown in Table 1 below:

<u>Table 1</u>: MCE Program Peak Demand Reduction Potential.

	Peak Demand Reduction Potential (MW)		**Budget Request ($)**
	2022	**2023**	
Peak FLEXmarket	15	30	$11,560,000
Energy Storage Program	2	3.8	$4,408,000
MCEv Sync	2.5	5	$1,776,000
TOTAL	**19.5**	**38.8**	**$17,744,000**

- Reject auto-enrollment provisions for IOU DR programs, and instead implement policies that will support a level-playing field across DR providers, including CCAs. CCAs have developed innovative programs tied to their customers' needs and are poised to deliver significant peak demand reduction benefits.
- Direct quarterly data sharing of DR program enrollment and other relevant data between IOUs and CCAs to streamline program development, customer enrollment, and to avoid dual participation issues and customer confusion. Convene a stakeholder workshop to develop the data sharing guidelines as needed.
- Continue to leverage SCTs as a key component of customer engagement by maintaining existing support for local SCT program funding and avoiding shortsighted limitations on SCT installations.

MCE thanks the Commission for its consideration of these proposals.

Dated: September 20, 2021

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

REPLY BRIEF OF MARIN CLEAN ENERGY

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September 27, 2021

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

SUMMARY OF RECOMMENDATIONS

Marin Clean Energy ("MCE") urges the Commission to adopt the complete list of recommendations included in MCE's Opening Brief. However, MCE focuses this Reply Brief on the following recommendations in response to certain parties' opening briefs:

- The Commission should fund MCE's three program proposals, rather than modify the Emergency Load Reduction Program ("ELRP"), since MCE's program offerings present a realistic opportunity to quickly achieve meaningful peak demand reductions in time for summers 2022 and 2023, as described herein and shown in Table 1 below.

Table 1: MCE Program Peak Demand Reduction Potential.

	Peak Demand Reduction Potential (MW)		**Budget Request ($)**
	2022	**2023**	
Peak FLEXmarket	15	30	$11,560,000
Energy Storage Program	2	3.8	$4,408,000
MCEv Sync	2.5	5	$1,776,000
TOTAL	**19.5**	**38.8**	**$17,744,000**

- The Commission should facilitate increased coordination by demand response ("DR") program providers to ensure a streamlined customer enrollment process and dual participation verifications. To this end, the Commission should:

  (1) Require a formal, quarterly process for investor-owned utilities to share customer enrollment data, which CCAs are authorized to receive;

  (2) Ensure that an appropriate non-disclosure agreement ("NDA") to share such data is established expeditiously, should the Commission deem the existing NDA insufficient;

(3) Reject PG&E's misplaced arguments that such data sharing conflicts with California or U.S. law, especially for other load-serving entities ("LSEs"), like MCE, that are entitled to such data;

(4) Direct investor-owned utilities ("IOUs") to initiate customer enrollment data transfers within 90 days of issuing a final decision;

(5) To the extent that any changes to the existing NDA are deemed necessary, the Commission should require adoption of these changes prior to the completion of this 90-day deadline; and

(6) As a longer-term measure, convene a working group to discuss increased collaboration and develop additional data-sharing guidelines between IOUs and CCAs to improve DR programming.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

REPLY BRIEF OF MARIN CLEAN ENERGY

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and Commissioner Batjer's August 10, 2021 Amended Scoping Ruling ("Amended Scoping Ruling"),[1] MCE[2] hereby submits this Reply Brief in Phase 2 of the above-captioned *Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021* ("Rulemaking").[3]

The Amended Scoping Ruling establishes the scope for this Phase 2 and invites party comment on ways to address Governor Newsom's July 30, 2021 Emergency Proclamation ("Emergency Proclamation"),[4] which directed all state agencies "to act immediately" to find ways to make up for the "projected energy supply shortage of up to 3,500 megawatts ["MW"] during the afternoon-evening 'net-peak' period of high power demand on days where there are extreme

[1] Rulemaking ("R.") 20-11-003, *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2*, p. 6 (August 10, 2021) ("Amended Scoping Ruling").
[2] MCE, California's first CCA, is a not-for-profit public agency that began service in 2010 with a mission of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs. MCE is a load-serving entity ("LSE") serving approximately 1,200 MW of peak load, providing electricity generation services to more than 1.1 million people in 36 member communities across Contra Costa, Marin, Napa, and Solano counties. (*Marin Clean Energy Prepared Direct Testimony of Alice Havenar-Daughton in Rulemaking 20-11-003* (September 1, 2021), p. 1-2:4-9 (hereafter "MCE Phase 2 Testimony").
[3] *See* Amended Scoping Ruling, p. 3 ("This phase of the proceeding will be known as 'Phase 2 – Reliability for 2022-23 – Update' (Phase 2)."
[4] Proclamation of a State of Emergency ("Emergency Proclamation"), July 30, 2021, *accessible at* https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.

weather conditions."[5] The purpose of this Rulemaking is to identify ways to both increase energy supply and to decrease demand during the peak demand and net peak demand hours in 2022 and 2023.[6] Phase 2 also invites consideration of "changes to current [Commission] requirements" that might be "needed to meet Governor Newsom's emergency proclamation."[7]

I. INTRODUCTION

The energy supply shortage identified in the Emergency Proclamation requires quick action to significantly reduce electricity demand during peak periods. This Rulemaking considers program proposals and rule modifications that will achieve this goal. While parties have identified numerous possibilities towards this end, MCE agrees with those who note that the Commission must leverage programs that are "realistic to implement with speed," and clearly capable of achieving significant reliability benefits, to meet the looming energy supply shortage by June 1, 2022.[8] Thus, rather than imposing complicated changes to the ELRP, which has proven to not be effective, the Commission should focus its efforts on programs that can perform and scale quickly. MCE's three program proposals – the *Peak FLEXmarket*, the *Energy Storage Program* and *MCEv Sync* – are already developed and meet the exigencies of this emergency situation.

Additionally, better coordination is required between CCAs and IOUs to achieve effective demand reduction, especially on the fast timeline required by the Emergency Proclamation and this Rulemaking. This requires both immediate action in requiring IOU data-sharing of customer enrollment information, and long-term solutions to ensure that disparate program administrators implement DR programs in a consistent and complementary manner. As explained below, the

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5 *Id*.

6 Amended Scoping Ruling, pp. 3-4; *see also Assigned Commissioner's Scoping Memo and Ruling* (December 21, 2020), p. 1.

7 Amended Scoping Ruling, p. 4.

8 *Opening Brief of Pacific Gas and Electric Company (U 39 E) on Phase 2 Issues*, p. 3 (September 20, 2021) (hereafter "PG&E Opening Brief").

utilities' alleged concerns regarding sharing data with CCAs is misplaced because CCAs are LSE that are entitled by law to receive private customer data.

Consistent with these principles, MCE submits the following responses and recommendations for the Commission's consideration.

II. FUNDING MCE'S PROGRAM PROPOSALS, RATHER THAN ADOPTING UNPROVEN PROGRAM MODIFICATIONS TO AN UNDERPERFORMING DR PROGRAM (ELRP), IS CONSISTENT WITH THE GOALS OF THE EMERGENCY PROCLAMATION.

Limited ratepayer resources should be directed towards programs that can quickly achieve verifiable reliability benefits. Adhering to this principle will result in the most prudent use of ratepayer dollars and is necessary to achieve the Emergency Proclamation's mandate to deliver quantifiable grid reliability benefits by summer 2022, *i.e.*, *in less than nine months*.

As several parties recognize, there are significant implementation and performance challenges with the ELRP, both in its current form and with proposed modifications.[9] Rather than directing stakeholder and ratepayer resources to a program that will require complex and uncertain improvements and that numerous parties (including Energy Division Staff) find is not meeting its intended grid reliability goals, the Commission should direct funding to programs that offer a simple, streamlined means to quickly achieve verifiable and significant grid reliability benefits. Each of MCE's three program proposals, and especially the *Peak FLEXmarket*, meets these goals.

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[9] *See, e.g.*, Energy Division Staff Concept Paper, August 16, 2021, p. 3 ("Staff Concept Paper") (proposing program changes "to increase participation and program effectiveness"), p. 4 (recognizing that the program's existing compensation collar "may be overly complicated for customers"), *id.* (identifying possible "equity and effectiveness" concerns with the program's eligibility criteria); *see also Opening Brief of the California Solar & Storage Association*, p. 3 (September 20, 2021) (hereafter "CALSSA Opening Brief"); *Southern California Edison Company's (U 338-E) Opening Brief*, p. 39 (September 20, 2021) (hereafter "SCE Opening Brief").

A. Each of MCE's Program Proposals Presents a Realistic and Quickly Actionable Opportunity to Provide Significant Grid Reliability Benefits by Summer 2022.

The Emergency Proclamation calls for 'immediate action' to address the State's projected energy supply shortage of up to 3,500 megawatts ("MW") during afternoon-evening 'net peak' period of high power demand on days where there are extreme weather conditions."[10] As Pacific Gas & Electric Company ("PG&E") notes, "[i]n order to make meaningful progress" towards these goals, "the Commission [should] focus on proposals…that present the opportunity for significant reliability benefits and are realistic to implement with speed following adoption of a final decision in this proceeding."[11] MCE fully agrees. While there were "numerous proposals from intervenors in prepared testimony that are complicated, difficult to implement, expensive, and require costly long-term commitments,"[12] MCE's programs are *already up and running* and can hence be leveraged to quickly and cost-effectively achieve improved grid reliability in the summers of 2022 and 2023. In other words, they present a realistic "opportunity [to obtain] significant reliability benefits… following adoption of a final decision in this proceeding."[13]

As shown in Table 1 below, MCE projects a total peak demand reduction potential of 19.5 MW by summer 2022, and 38.8 MW by summer 2023.

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[10] Emergency Proclamation; *see also* Amended Scoping Ruling, pp. 3-4.
[11] PG&E Opening Brief, p. 3.
[12] *Id.*
[13] *Id.*

Table 1: MCE Program Peak Demand Reduction Potential.

	Peak Demand Reduction Potential (MW)		Budget Request ($)
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MCE has a proven track record of running customer programs,[14] has already developed best practices and lessons learned,[15] and is well-positioned to act quickly and to deliver on its projected peak demand reduction targets. Finally, the fact that MCE has already designed and developed all three of its proposed programs also means that MCE has already overcome initial start-up challenges and paid for the vast majority of the program startup costs through its own ratepayer generation revenues.

In summary, leveraging these existing programs proposed by MCE presents a simple, streamlined, and realistic opportunity to produce verifiable reliability benefits on the timeline mandated by the Emergency Proclamation. The Commission should accordingly authorize MCE's three programmatic funding requests.

14 As explained in MCE's Opening Brief and testimony, MCE has extensive experience running customer programs that span the entire breadth of distributed energy resources ("DERs") from EE and energy storage to DR and Transportation Electrification ("TE"). (MCE Phase 2 Opening Testimony, p. 1-2:10-12; *Opening Brief of Marin Clean Energy*, p. 14 (September 20, 2021) (hereafter "MCE Opening Brief")).

15 MCE has served as a Program Administrator of ratepayer-funded EE programs since 2013, and subsequently expanded its DER program portfolio to include initiatives focused on low-income solar, community solar programs for disadvantaged communities, energy storage, DR and TE. (MCE Phase 2 Opening Testimony, p. 1-2:23-26; MCE Opening Brief, pp. 14-15.)

B. The ELRP, Including Proposed Modifications, Raises Numerous Challenges and Does Not Present the Best Solution to Address California's Grid Reliability Emergency.

The Commission adopted the ELRP in March of 2021 as a five-year pilot DR program to help avoid rotating outages in the summers of 2021 and 2022.[16] ELRP is designed to compensate customers for voluntarily reducing demand on the grid when called upon by the CAISO in the event of a grid emergency.[17] However, as recognized by multiple parties and the Staff Concept Paper, ELRP has failed to meet expectations in both program enrollment and delivered reliability benefits.[18]

More specifically, CALSSA correctly observes that "[t]he primary issues impeding the ELRP program are difficulties in customer enrollment and in estimating customer benefits, or even being assured that the program will result in compensable dispatches."[19] CALSSA notes that, since the program is designed to trigger demand reduction in response to a CAISO-called Alert, Warning and Emergency ("AWE") events, ELRP delivers very infrequent benefits.[20] As a result, Commission staff, utilities, and parties "spend a significant amount of time, work and effort to develop a program that is likely to be dispatched very infrequently."[21] To address this shortcoming and to "provide some level of investment certainty", the California Energy Storage Association

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16 Decision ("D.") 21-03-056, *Decision Directing PG&E, SCE and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and* 2022, issued March 26, 2021 in Rulemaking 20-11-003, Ordering Paragraph 7.

17 *See id.* at 26.

18 Staff Concept Paper, p. 3 (proposing program changes "to increase participation and program effectiveness"), *id.* at 4 (recognizing that the program's existing compensation collar "may be overly complicated for customers"), *id.* (identifying possible "equity and effectiveness" concerns with the program's eligibility criteria); *see also* CALSSA Opening Brief, p. 3, SCE Opening Brief, p. 39.

19 CALSSA Opening Brief, p. 3.

20 CALSSA elaborates that in both 2016 and 2018, CAISO called zero AWE events, and in 2017 and 2019, CAISO called only one such event in each year. *See* CALSSA Opening Brief, p. 3.

21 CALSSA Opening Brief, p. 3.

("CESA") suggests the ELRP program should be modified to "increase the amount of times ELRP systems are dispatched."[22]

In addition to falling short on providing much needed grid reliability benefits, the low frequency of ELRP dispatch also means that there is very little customer value in program participation. To remedy this issue, several parties argue that capacity or reservation payments are needed to encourage increased customer participation.[23] CESA states that these payments "are needed to encourage more customers and aggregators to participate in the program and provide deeper assurances that load reductions and/or exports are provided."[24] However, the utilities voice concerns about providing capacity payments due to the lack of accountability, performance assurances, and "free ridership" concerns.[25]

MCE agrees with the identified concerns and urges the Commission to direct ratepayer resources towards programs that are more likely to meet this Rulemaking's grid reliability goals, such as MCE's three program proposals, and particularly its *Peak FLEXmarket* program, which is designed to solve for the concerns described above.

i. The Programs Proposed by MCE Provide Additional Customer and Grid Value Through Daily Load Shift Payments.

MCE agrees with CESA's statement that payments outside of event-based compensation are required to encourage customer participation under DR programs.[26] In fact, MCE developed

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[22] *Opening Brief of the California Energy Storage Alliance*, p. 10 (September 20, 2021) (hereafter "CESA Opening Brief").
[23] *Opening Prepared Testimony of Joint Demand Response Parties (CPower and Enel North America, Inc.)*, p. 24 (September 1, 2021) (hereafter "Joint DR Parties Phase 2 Opening Testimony"); *Opening Prepared Testimony of Voltus, Inc.*, p. 3 (September 1, 2021) (herafter "Voltus Phase 2 Opening Testimony"); *Prepared Direct Testimony of Carl Lenox, Senior Director, Electrification and Advanced Product Management, Alexander Sherman, Director, Sunrun Energy Services on behalf of Sunrun Inc.*, p. 16 (September 1, 2021); *Prepared Direct Testimony of the California Solar & Storage Association*, p. 9 (September 1, 2021) (hereafter "CALSSA Phase 2 Opening Testimony").
[24] CESA Opening Brief, p. 9.
[25] *See* PG&E Opening Brief, p. 7; SCE Opening Brief, p. 40.
[26] CESA Opening Brief, p. 9.

all three of its proposed programs – the *Peak FLEXmarket*, the *Energy Storage Program*, and *MCEv Sync* – with the main goal to provide *daily* load shifting during the summer months.[27] MCE hence actively engages customers all throughout the summer, rather than being limited to infrequent event dispatches.

This compensation model offers several strategic benefits. First, it ensures that load shifting becomes common practice, consistent and achievable, rather than leaning on DR purely as an emergency lever. Second, offering payments for daily load shifting in addition to event-based DR increases customer benefits and program value, which in turn encourages participation. Third, there are carbon, grid resiliency and cost benefits if load-shifting is more commonly practiced. Thus, because MCE's program proposals offer a higher-reward and higher-impact opportunity, the Commission should authorize their funding as requested herein, rather than losing ground on continued efforts to improve ELRP.

ii. The *Peak FLEXmarket*'s Simple, Market-Based and Technology-Agnostic Program Design Encourages Participation and Allows for Quick Expansion.

In contrast to the slow customer enrollment under the ELRP, MCE's *Peak FLEXmarket* program has attracted strong interest right since it first launched on June 1, 2021. In fact, within the first three months of program operations, four aggregators submitted their first enrollments, with 1,465 meters assessed for eligibility, and 304 meters being actively tracked within aggregator portfolios.[28] As of the filing of this Reply Brief, these numbers have already grown to 6 enrolled aggregators, a total of 2,900 meters assessed for eligibility, and 1,415 meters being actively tracked within aggregator portfolios.

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27 MCE Phase 2 Opening Testimony, p. 2-4: 22-24, 2-5: 1-15, p. 2-20: 9-19, p. 2-32:10-17.

28 *Id.* at 2-6:8-11.

The *Peak FLEXmarket* is also uniquely poised to scale and achieve meaningful peak demand reductions by June 1, 2022 due to its innovative program design. The program is based on a simple, market-based platform that integrates DR opportunities across various technologies and program offerings.[29] This approach avoids prescriptive solutions for how load reductions should occur and instead enables participation of a broad range of demand flexibility providers, including those that have traditionally not participated in DR programs. It further allows MCE to scale the program quickly by avoiding the administratively burdensome process of launching direct contracts with each participating aggregator.[30]

In summary, MCE agrees with the multitude of challenges raised by parties regarding ELRP in both its current form and with proposed modifications. The magnitude of the identified grid reliability needs, and the rapid timeline identified in the Emergency Proclamation, necessitate the Commission's focus on simpler, higher-reward and higher-impact programs that can be quickly implemented to deliver grid reliability benefits. All three of MCE's program proposals, and especially the *Peak FLEXmarket*, meet these objectives.[31]

III. INCREASED COORDINATION BETWEEN CCAS AND IOUS IS NECESSARY TO FULLY LEVERAGE PEAK DEMAND REDUCTIONS.

The near-term and significant energy supply shortage identified in the Emergency Proclamation necessitates consideration of all available measures to reduce peak and net peak demand.[32] The Commission must act accordingly to broaden DR program implementation beyond programs that are exclusively run by IOUs and/or in coordination between IOUs and third-party

29 *See* MCE Opening Brief, pp. 31-32.
30 *See* MCE Phase 2 Opening Testimony, p. 2-4: 5-14.
31 *See* MCE Opening Brief, pp. 7-27; MCE Phase 2 Opening Testimony, Chapter 2 (A. Havenar-Daughton).
32 Emergency Proclamation (describing an energy supply shortage of up to 3,500 MW during afternoon-evening "net peak" period of high-power demand on days when there are extreme weather conditions); *see also* Amended Scoping Ruling.

Demand Response Providers ("DRPs"). More specifically, MCE urges the Commission to consider CCAs as important partners in implementing new DR programs that must be brought to market quickly.

Still, MCE appreciates PG&E's concern that certain party proposals may overlap or pose "interference" with others such as those run by PG&E.[33] MCE agrees that increased coordination between DR program providers is necessary and in furtherance of the goals of this Rulemaking, since coordination will improve efficiencies, allow for sharing of best-practices, and maximize grid reliability benefits.

Accordingly, and as further described in Section IV below, MCE recommends that the Commission require data-sharing and increased communication among parties to improve DR program coordination and maximize customer impacts. Specifically, MCE urges the Commission to take the following steps in support of improving stakeholder coordination: (1) require quarterly sharing of customer enrollment data between IOUs and CCAs; (2) convene a working group between IOUs, CCAs and DRPs to further coordinate on DR programs and program implementation.

IV. THE COMMISSION SHOULD REJECT PG&E'S PRIVACY ARGUMENTS AND MANDATE PROGRAM PARTICIPATION DATA-SHARING, CONSISTENT WITH COMMISSION POLICIES AND THE GOALS OF THIS RULEMAKING.

As discussed above, improved coordination among DR program administrators and stakeholders is necessary to meet the goals of this emergency Rulemaking, and to comply with existing Commission policies. The Emergency Proclamation requires state agencies "to act immediately" to identify solutions that will mitigate the effects of climate change and reduce peak

33 PG&E Opening Brief, p. 24.

and net peak grid demands.[34] Given these exigencies, stakeholders should take every action to streamline new DR customer enrollment and maximize impact. This requires clear, consistent and direct information regarding customer DR participation. Indeed, SDG&E also acknowledges that "a comprehensive discussion of data-sharing could be fruitful."[35]

As outlined in more detail in section IV.A below, MCE requires customer participation data mainly to verify compliance with dual participation prohibitions under DR programs. Additionally, MCE can maximize value by using customer participation information to focus its marketing efforts to efficiently reach customers that are not already participating in DR programs. The Emergency proclamation specifically sets forth the goal of achieving *incremental* grid reliability. Hence, MCE must target new customers that are not already making efforts to shift loads away from peaks. Enrolling new customers that are not currently enrolled in DR is consistent with this goal.

Hence, MCE urges the Commission to act immediately to (1) establish a formal, quarterly process for IOUs to share customer enrollment data; (2) ensure that an appropriate non-disclosure agreement ("NDA") to share customer enrollment data with CCAs is established expeditiously; and (3) reject PG&E's misplaced arguments that data-sharing conflicts with California or U.S. law, especially for other LSEs, like MCE, that are entitled to such data. These actions are necessary to meet the immediate needs identified in this Rulemaking. In the longer term, MCE recommends that the Commission convene a working group to discuss increased collaboration and develop data-sharing guidelines between IOUs, CCAs and DRPs to improve DR programming and customer engagement, as noted above.

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34 Emergency Proclamation, Ordering Paragraph 2.

35 *Prepared Phase 2 Reply Testimony of San Diego Gas & Electric Company Regarding Demand-Side Actions to Reduce Peak and Net Peak Demand in 2022 and 2023*, p. 11:4-11 (September 10, 2021).

A. The Commission Should Require Quarterly Sharing of Customer Enrollment Information for All Customers to Avoid Dual Enrollment.

Existing Commission policies prohibit customers from participating in two DR programs at the same time ("dual participation prohibition").[36] Hence, MCE requires customer enrollment information to verify compliance with this policy prior to enrolling a new customer in one of MCE's demand flexibility programs.[37] More specifically, MCE requires information to confirm (1) whether a particular customer is currently enrolled in *any other* DR program run by an IOU or DRP, and (2) which DR program the customer is enrolled in. This information is essential to confirm that enrolling a certain customer will not violate the Commission's dual enrollment prohibition, and, as detailed below, MCE is entitled to the information as an LSE.

PG&E is correct that MCE's request in this instant rulemaking is different from the Rule 24 process through which MCE and other CCAs receive information to enable them as LSEs to accept or reject their customer's registration in the CAISO Demand Response Registration System.[38] Rule 24 provisions have established a process to verify customer enrollment in *supply-side* DR programs and to prevent dual participation. However, dual enrollment prohibitions also apply to load-modifying resource ("LMR") DR programs and currently, there is no process in place to verify customer enrollment in IOU LMR DR programs. For example, the ELRP is a LMR DR program and MCE does not receive any information from the utility on customer enrollment in ELRP (or any other LMR DR program). Therefore, MCE is unable to verify customer enrollment status simply and quickly (through the utility) and instead must rely on information

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36 *See* SCE Electric Rule 24, p. 9 (prohibiting DRPs from enrolling a customer if that customer is already participating in a separate DR program); PG&E Electric Rule 24, p. 10 (prohibiting same); D.21-03-056, Appendix A.

37 *See* SCE Electric Rule 24, p. 9 (prohibiting DRPs from enrolling a customer if that customer is already participating in a separate DR program); PG&E Electric Rule 24, p. 10 (prohibiting same).

38 PG&E Opening Brief, p. 31, n. 133.

provided by the customer and/or aggregator to prevent dual participation in DR programs. This verification process would be much more streamlined, consistent and accurate if customer enrollment information were provided by the utility, or through an official process such as a "data clearinghouse" for LMR DR programs.

Furthermore, several parties raised alleged privacy concerns and other limitations to sharing individual customer or usage information with third parties, or with CCAs, if they are sharing bundled customer usage information.[39] These concerns are not applicable to MCE because CCAs are not "third parties," but rather, LSEs. As an LSE, MCE is statutorily entitled to customer and usage information under Public Utilities Code § 366.2(a)(9) and (21). MCE currently receives customer information regarding all bundled and unbundled customers within MCE's service area, including personally identifiable information (*i.e.*, the 4013 report)[40] and usage information (*i.e.*, interval data), among other data.[41] Thus, MCE has an existing right to usage information and other information related to the customer's participation in DR programs. Nevertheless, it is important to highlight that in this proceeding, MCE only requests the sharing of customer *enrollment* information since it is critical to complying with Commission policies. To reiterate, MCE is *not*

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39 *See, e.g.*, *Opening Brief of the California Large Energy Consumers Association* (September 20, 2021) (hereafter "CLECA Opening Brief"), PG&E Opening Brief, pp. 28-33; *Reply Testimony of Southern California Edison Company-Phase 2*, p. 9 (September 10, 2021) (hereafter "SCE Phase 2 Reply Testimony").

40 *See* Resolution (E-4013 (2006)), *available at* https://docs.cpuc.ca.gov/published/Graphics/61879.PDF.

41 D.05-12-041 at pp. 38-39 ("D.04-12-046 issued in Phase 1 of this proceeding directs the utilities to provide all relevant information to CCAs and prospective CCAs, consistent with Section 366.2(c)(9). In that order we stated 'AB 117 is clear in its intent to require the utilities to provide CCAs all customer and usage data even before the CCA begins offering service.' We have found that AB 117 does not permit the utilities to second guess a CCA's request for relevant information and we will not revisit the issue here. The utilities' tariffs, therefore, shall include a provision that permits CCAs to access all relevant customer information, consistent with D.04-12-046 and the tariffs filed in compliance with D.04-12-046.).

requesting additional customer usage or program participation information through a final decision on the Amended Scoping Ruling.

Further, if the Commission authorizes MCE's proposed program funding requests, the programs will be available to both bundled and unbundled customers.[42] Therefore, it is critical that MCE have access to enrollment information across bundled and unbundled customers, regardless of whether a customer is enrolled in a supply-side or LMR program, to ensure compliance with the Commission's dual participation prohibition.

In sum, limiting the DR participation information to only supply-side DR programs or only unbundled customers will fatally undermine MCE's ability to verify dual enrollment. The Commission should direct IOUs to share customer enrollment information in *any and all* DR programs to enable all DR program providers, including CCAs, to comply with existing Commission policies and the goals of this Rulemaking.

B. The Commission Should Ensure an Appropriate NDA is Established Expeditiously Between CCAs and IOUs to Share Customer Enrollment Data and Avoid Delays.

PG&E claims that its existing nondisclosure agreement ("NDA") with MCE, which was established to share data for the implementation of energy efficiency ("EE") programs, is insufficient to share the data needed here because the Commission's existing authorization is limited to Section 381.1 programs.[43]

Both the Emergency Proclamation and the Amended Scoping Ruling require immediate action and contemplate necessary program or policy modifications to expand the number of customers and MWs enrolled under DR programs.[44] The Commission should take any actions

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42 MCE Phase 2 Opening Testimony, p. 2-8:13-15 and p. 2-34:16-17.

43 PG&E Opening Brief, pp. 29-30.

44 Emergency Proclamation (requiring state agencies to "act immediately" to address the grid reliability needs); Amended Scoping Ruling, p. 2 (noting same).

possible in this Rulemaking to ensure this emergency need is met. If the Commission determines that its previous order establishing the NDA is insufficient to cover an exchange of the required DR data, then it should authorize the simple solution of expanding its existing NDA order to bring it in line with the needs of this Rulemaking.[45]

As mentioned above, CCAs have broad rights to customer data, including, but not limited to, billing and load data to implement CCA programs.[46] DR sits at the top of California's loading order and is a central component of the Commission's efforts to address reliability.[47] The Commission should make every effort to facilitate LSEs' ability to expand DR program enrollment, including by directing IOUs to share DR enrollment information with CCAs. Specifically, the Commission should direct IOUs to initiate any data transfers within 90 days of issuing a final decision, and, to the extent that any changes to the existing NDA are deemed necessary, the Commission should require adoption of these changes prior to the completion of this 90-day deadline.

C. PG&E's Arguments Raising the Specter of Competitive Neutrality, Antitrust, or Consumer Privacy Laws Should Be Dismissed.

PG&E contends that granting MCE's request to share customer participation and enrollment data may violate antitrust laws.[48] These concerns are unfounded and should be set aside.

As a preliminary note, despite PG&E's claims that sharing program participation information runs afoul of U.S. law, SCE states that it "already shares DR program participation

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45 *See* PG&E Electric Form 79-103, *available at* https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_FORMS_79-1031.pdf.

46 Cal. Pub. Util. Code § 366.2(9).

47 *See* MCE Opening Brief, pp. 6-7.

48 PG&E Opening Brief, pp. 32-33.

data with CCAs of customers served by those CCAs."[49] The fact that SCE currently shares this information with CCAs indicates that PG&E's arguments are not based on actual requirements or limitations, but instead on PG&E's preference to maintain exclusive control over the data.

PG&E claims that "MCE's stated purpose for using this [DR participation] data is so that it does not market DR to customers already signed up for another provider."[50] PG&E does not provide a citation supporting this statement and, in fact, incorrectly states MCE's position. As noted above, MCE seeks to prioritize marketing and enrolling new DR customers to achieve incremental reliability improvements during this emergency but will not exclusively market to, or serve, non-participants.

Further, PG&E incorrectly relies on *U.S. v. Sealy* (1967) 388 U.S. 350 in claiming that "sharing information with a competitor for [MCE's intended purpose] may run afoul of antitrust laws…or may facilitate allocating markets or customers among competitors."[51] In *Sealy*, licensees of the Sealy brand entered into agreements and established a system to divide customers upon geographic boundaries that included a restriction preventing more than one licensee from serving the same customers in a particular geography.[52] Here, no such boundary or limitation on service for DR programming exists. There is no arrangement or agreement that MCE or PG&E will not provide DR to a particular customer outside of mandated eligibility requirements. While it is true that both CCAs and IOUs have defined geographic service areas, within those areas there is no agreement or arrangement to limit participation to certain customers. Further, PG&E's sharing of the customer enrollment information MCE requested will not create any arrangements or agreements that would limit PG&E's, MCE's, or any other

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49 SCE Phase 2 Reply Testimony, pp. 9, 17-18.
50 PG&E Opening Brief, p. 32.
51 *Id.*
52 *U.S. v. Sealy* (1967) 388 U.S. 350.

DRP's ability to serve customers. Thus, *Sealy* is not relevant to PG&E sharing the requested DR enrollment information, and the Commission should dismiss PG&E's arguments.

Similarly, the Commission should reject PG&E's request to apply the state action doctrine in this application because sharing DR enrollment information does not displace competition. On the contrary, it enhances the ability of programs beyond just the IOUs to perform meaningful verification that customers are not enrolled in multiple DR programs. Though PG&E claims that specific information about one DRP's customer is market-sensitive and thus should not be shared with the DRP's potential competitor, MCE's request for limited information[53] and limited use of information[54] does not present a competitive threat to DRPs. The information and the use cases will allow MCE's programs to ensure compliance with eligibility requirements and provide the greatest opportunity to reduce peak loads during this grid emergency by facilitating new CCA-led DR programs.

Finally, the Commission should accord no weight to PG&E's unsupported claim that SCE's testimony "echoes the same concerns" raised by PG&E.[55] Upon examination, the cited portion of SCE's testimony does not raise a concern about competitive threats to DRPs or even a similar concern. SCE unrelatedly claims that sharing participation information with a CCA would raise customer privacy concerns and goes on to provide blanket cites to several Commission decisions or statutes related to customer privacy and sharing data with third parties generally.[56] None of the law SCE cites is controlling in this instance, particularly given that

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53 MCE is simply requesting to know whether a customer is enrolled and, if so, in what DR program. This does not require any performance or usage data.

54 MCE will use the data to verify compliance with dual-enrollment rules and focus a greater marketing effort on non-participating customers.

55 *See* PG&E Opening Brief, p. 31.

56 As discussed above, "third parties" are distinct from LSEs as LSEs, including CCAs, have greater statutory rights to individual customer data, including usage data. Cal. Pub. Util. Code §§ 366.2(9) and (21).

CCAs are permitted by state law to receive customer information.[57] PG&E's assertion that SCE's cited testimony supports their claim is incorrect and should be disregarded. Likewise, PG&E's passing reference to the Commission's existing approach being consistent with the California Consumer Privacy Act and the California Privacy Rights Act is not accompanied by any specific or coherent arguments relating to how a different approach may be inconsistent with those laws and should be accorded no weight.

For the aforementioned reasons, the Commission should uniformly dismiss PG&E's arguments related to competitive neutrality, antitrust and U.S. privacy laws.

V. CONCLUSION

MCE respectfully urges the Commission to take the following actions, in addition to adopting the complete list of recommendations included in MCE's Opening Brief.

- The Commission should fund MCE's three program proposals, rather than modify the ELRP, since MCE's program offerings present a realistic opportunity to quickly achieve meaningful peak demand reductions in time for summers 2022 and 2023, as described herein and shown in Table 1 below.

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[57] Collectively, the laws cited in SCE's testimony limit the IOU's ability to share usage data with an unauthorized entity or establish means to share usage data with non-LSEs. (*See* SCE Phase 2 Opening Testimony, p. 9, lines 18-20, and footnote 14.) However, CCAs already have access to customer and smart meter/usage data as LSE. *See* Cal. Pub. Util. Code §§ 366.2(9) & (21).

<u>Table 1</u>: MCE Program Peak Demand Reduction Potential.

	Peak Demand Reduction Potential (MW)		**Budget Request ($)**
	2022	**2023**	
Peak FLEXmarket	15	30	$11,560,000
Energy Storage Program	2	3.8	$4,408,000
MCEv Sync	2.5	5	$1,776,000
TOTAL	**19.5**	**38.8**	**$17,744,000**

- The Commission should facilitate increased coordination by DR program providers to ensure a streamlined customer enrollment process and dual participation verifications. To this end, the Commission should:

  (1) Require a formal, quarterly process for IOUs to share customer enrollment data, which CCAs are authorized to receive;

  (2) Ensure that an appropriate NDA to share such data is established expeditiously, should the Commission deem the existing NDA insufficient;

  (3) Reject PG&E's misplaced arguments that such data sharing conflicts with California or U.S. law, especially for other LSEs like MCE, that are entitled to such data;

  (4) Direct IOUs to initiate customer enrollment data transfers within 90 days of issuing a final decision;

  (5) To the extent that any changes to the existing NDA are deemed necessary, the Commission should require adoption of these changes prior to the completion of this 90-day deadline; and

(6) As a longer-term measure, convene a working group to discuss increased collaboration and develop additional data-sharing guidelines between IOUs and CCAs to improve DR programming.

These actions are necessary to meet the immediate needs identified in this Rulemaking. MCE thanks the Commission for its consideration of these proposals.

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Respectfully submitted,

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