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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

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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.

[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

[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.

Program Enrollment

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;

[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.

<u>Table 2</u>: *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**

- <u>Program Administration</u>

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).

2. Customer incentive payments

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.

3. ME&O

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.

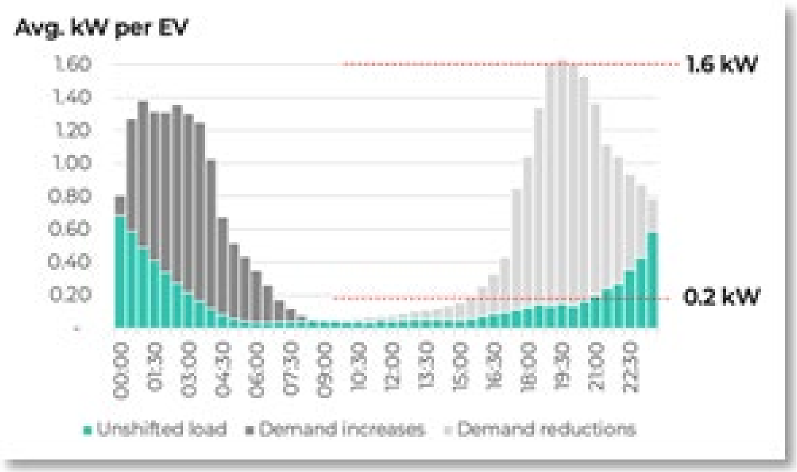
ii. Demonstration that program will deliver benefits during net peak

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.

<u>Figure 1</u>. 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.

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[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,

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[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.

2. Customer Incentives

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

3. ME&O costs

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.

4. M&V costs

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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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]

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[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

[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.