# AUGUST FILINGS

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

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

**COMMENTS OF MARIN CLEAN ENERGY**
**ON THE JULY 22, 2021 EMAIL RULING**


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July 30, 2021

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

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

**COMMENTS OF MARIN CLEAN ENERGY**
**ON THE JULY 22, 2021 EMAIL RULING**

## I. Introduction

Marin Clean Energy ("MCE") provides these comments in accordance with the July 22, 2021, *Email Ruling Providing Notice and Opportunity RE: Additional Results of Draft Potential and Goals Study* ("Email Ruling") of Administrative Law Judge Kao in the above-captioned proceeding.

## II. Comments

MCE strongly supports the hybrid approach proposed in the Email Ruling as the best available approach. The Email Ruling proposes a hybrid approach to setting energy efficiency ("EE") goals for 2022-2032. Under this approach, the Commission directs program administrators ("PAs") to set the 2022-2023 goals using a scenario based on the 2020 Avoided Cost Calculator ("ACC"), which produced updated results on July 14, 2021, consistent with Decision ("D.") 21-05-031.[1] At the same time, the Commission proposes to amend D.21-15-031 to set 2024-2032 goals using the 2021 ACC and to direct PAs to use the 2021 ACC for developing their 2024-2027 portfolio and budget applications which are due in early 2022. The Email Ruling requests that parties explain whether they agree or disagree with this "hybrid" approach. The ruling also asks

[1] D.21-05-031, Assessment of Energy Efficiency Potential and Goals and Modification of Portfolio Approval and Oversight Process, from May 20, 2021, at p. 52

commenters to indicate which scenario should be adopted for setting the 2022-2023 and the 2024-2032 goals. MCE takes no position on the latter question but sets out its support for the hybrid approach below.

MCE appreciates the Commission's responsiveness to stakeholder concerns and supports the Commission's proposed hybrid approach to setting the investor-owned utilities' ("IOUs'") 2022-2023 goals based on the 2020 ACC and the IOUs' 2024-2032 goals based on 2021 ACC. This is the best solution that addresses stakeholder concerns about using the 2020 ACC for the IOUs' potential and goals ("P&G") study while preventing unnecessary and extensive re-planning of the upcoming budget advice letter, especially for the smaller non-IOU PAs, who do not have EE savings goals set by the P&G study. MCE and other PAs have already invested substantial resources to prepare their program plans and budget advice letters for the years 2022-2023 and have used the 2020 ACC in doing so. Hence, MCE strongly supports the Commission's proposal to continue using the 2020 ACC for the upcoming budget advice letter for program years 2022-2023. Using the 2020 ACC to file the budget advice letters due this fall does not prevent PAs from using the 2021 ACC for strategic plans and implementation contract purposes now that updated P&G study results using the 2021 ACC are available.

Furthermore, while the 2021 ACC is substantially different from the 2020 ACC, the Commission took the most critical step of ensuring that the EE goal-setting process is aligned with the most current and accurate data from the 2021 ACC in the updated P&G study. Stakeholders now understand the long-term impacts of the 2021 ACC updates on EE's cost-effectiveness, economic, and market potential. Therefore, it is appropriate to apply the 2021 ACC to the 2024-2027 planning period even though it is not applied to the 2022-2023 period.

## III. Conclusion

MCE appreciates the opportunity to provide these comments and supports adoption of the proposed hybrid approach in the July 22, 2021 Email Ruling.

Respectfully submitted,

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Dated: July 30, 2021

# Submit comment on July 13, 2021 workshop presentations and discussion

Initiative: External load forward scheduling rights process

**1. Please provide your organization’s perspective on the stakeholder presentations and any near-term or long-term enhancements that were presented, as well as any other aspects of their presentation.**

For purposes of these comments, the Joint California LSEs include CalCCA, PG&E, SCE, SDG&E, the Six Cities, and the Bay Area Municipal Transmission Group.

The Joint California LSEs appreciated the opportunity to hear from different stakeholders on their perspectives for the direction and guiding principles for this initiative. In particular, after a challenging and contentious stakeholder initiative to create an interim solution for summer 2021, the Joint California LSEs value the openness and cooperative nature of the other stakeholders participating in the workshop. We hope that all stakeholders share a goal of creating a long-term, durable solution that equitably balances the need and right to protect the reliability of service to native load along with providing fair and open access to the CAISO grid for external parties. The Joint California LSEs look forward to engaging further with the diverse group of stakeholders to create a long-term policy that provides certainty that the CAISO can serve native load and affords external parties confidence in their ability to access the CAISO grid.

While generally a constructive workshop, the Joint California LSEs have concerns that some stakeholders may still be focused upon matters that have already been settled by FERC. The continued argument that the CAISO RA framework undermines external transmission rights is unproductive, as it is irrelevant to the core issues in this initiative and disregards FERC policy. This initiative is not focused on the FERC-accepted CAISO RA framework but, rather, on fairly allocating the CAISO’s limited transmission capacity during tight system conditions. The proper venue to express perspectives regarding the RA framework is the ongoing RA Enhancements initiative. Moreover, the question of whether the CAISO is undermining external transmission rights has already been addressed by FERC in its recent order accepting the export, load, and wheeling priorities tariff amendments. FERC

> disagree[d] with protestors that CAISO’s proposal constitutes a degradation of any firm transmission products. CAISO’s proposal only established scheduling priorities across the CAISO-controlled transmission system. Firm transmission rights to the boundary of CAISO’s system do not grant firm transmission rights across CAISO’s system, which, as noted above, do not exist.

(P 146). Indeed, this is true for any use of transmission crossing multiple Balancing Authorities. Holding of firm transmission rights in one BA does not provide for firm transmission rights in any other BA.  Continuing to entertain this erroneous argument will only frustrate the advancement of this initiative.

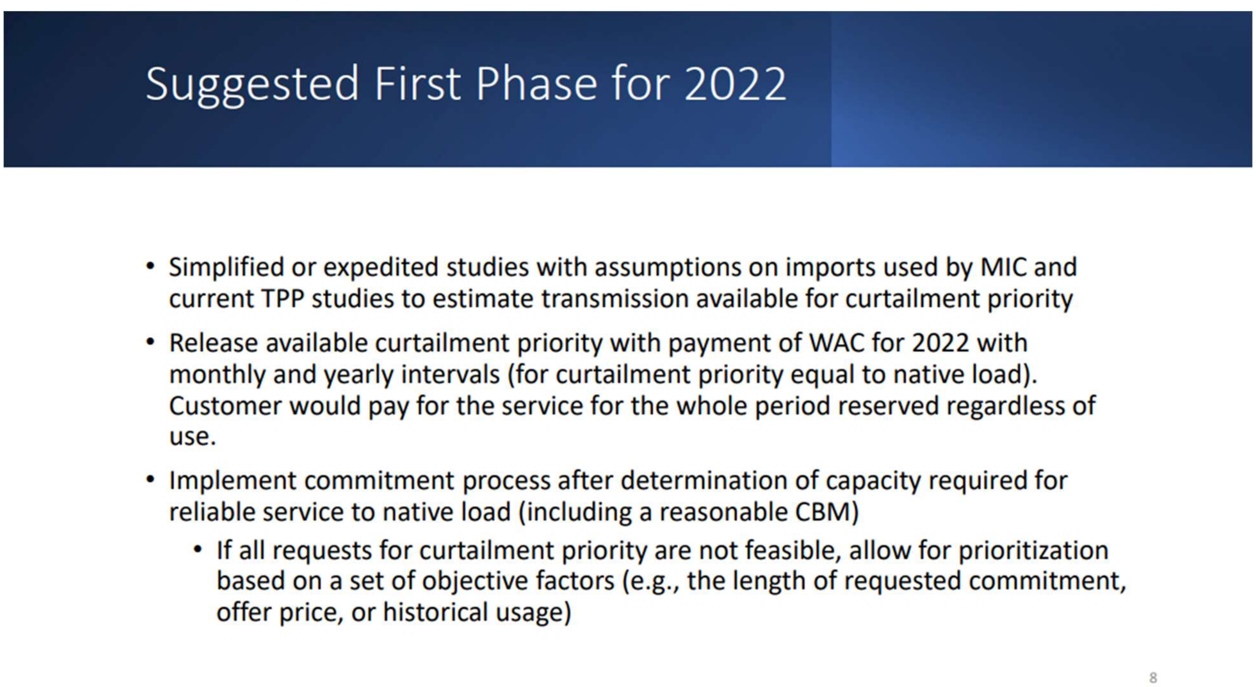
In addition, parties that express concern regarding the perceived devaluation of transmission rights on external systems  should recognize that, under the current tariff provisions, wheeling transactions over the CAISO system provide no long-term, on-going support for the costs of the CAISO grid. In contrast to CAISO LSEs, who pay CAISO grid costs on an on-going basis, entities that use the CAISO grid for wheeling transactions pay the Wheeling Access Charge only when they choose to schedule wheeling transactions. Such intermittent payments are not comparable to the cost responsibilities borne by CAISO LSEs, and they do not provide a basis to argue for a curtailment priority equivalent to CAISO load.

**2. Please provide your organization's perspective on the proposed phasing of the initiative.**

The Joint California LSEs propose CAISO work toward taking a conceptual long-term framework and a First Phase of Implementation to the CAISO Board in March 2022 followed by development of long-term implementation details in a later stage(s). Acknowledging the difficulty of implementing a long-term solution due to the likely changes with interdependent CAISO processes (e.g., MIC, TPP), the First Phase could use simplified studies and processes until long-term studies and processes can be developed and implemented.

**3. Please provide your organization's suggestions on near-term enhancements to the interim scheduling priority framework and requirements that could be implemented by summer 2022.**
*This includes suggestions on improvements regarding establishment of PT wheel and PT export status, and associated validations and processes.*

The Joint California LSEs continue to support the enhancements as described in our presentation in the "Suggested First Phase" slide (Slide 8, see below), as it would move the CAISO toward a long-term solution similar to the common practices of other RTO/ISOs.



The Joint California LSEs believe that one early phase enhancement where there may be alignment with external entities is the implementation of a new product where external parties would pay the CAISO directly for a high curtailment priority when capacity is available. Although we supported the external firm transmission rights requirement as an interim solution to ensure that an external entity is adequately committed to the CAISO grid such that a high curtailment priority within the CAISO system is appropriate, we do not view this as the most efficient market design. The Joint California LSEs suggest removing the need for this proxy by creating a high curtailment priority product as described in our presentation. Through the payment for this product, an external party would be providing sustained cost support for the CAISO grid. Moreover, it is consistent with the standard practices of other BAAs and RTOs.

In regard to PT exports, the Joint California LSEs would like the CAISO to consider certain enhancements to ensure that (1) a PT export is actually deliverable to the indicated export intertie, and (2) resources significantly deviating from their export schedules are curtailable. It is unclear if these enhancements can be implemented in a near-term timeframe, but we believe these should be explored as a part of this initiative.

**4. Please provide your organization's suggested principles and/or objectives for a long-term, durable, framework.**

Again, the Joint California LSEs support the framework described in our presentation on Slide 6. We believe this framework represents a reasonable solution that appropriately balances the need to reliably serve native load while also providing fair access to external entities. Moreover, it is consistent with the standard practices of other RTO/ISOs.

**5. Please provide your organization's perspectives on a problem statement that should guide development of a long-term framework.**

Consistent with our presentation (Slide 4), the Joint California LSEs offer the following problem statement:

> Develop principles and provisions for access to the CAISO grid for wheeling transactions and exports consistent with FERC's Open Access Transmission policy, including priority for native load requirements.

**6. Please provide your organization's suggestions for any approaches or frameworks that the ISO should consider for a long-term solution.**
*If possible or if available, please include references to any supporting documents whether FERC guidance, benchmarking of practices, or any other supporting information.*

The Joint California LSEs believe the recent FERC decision approving the export, load, and wheel-through tariff amendments provides the CAISO with helpful guiding principles for near- and long-term solutions. In particular, we would like to highlight the following principles from that decision:

- The transmission operator can reserve capacity in order to reliably serve its native load (P 143)
- The requirements for native load and external entities do not need to be equal (P 152)
- External transmission rights should not affect the priority internal to the CAISO (P 146)

The standard practices of other RTOs/ISOs have informed our long-term framework, and we encourage the CAISO to continue to look toward these standard practices to evaluate how they can be applied within the CAISO market.

**7. Please provide your organization's perspectives on any seams issues between the Open Access Transmission Tariff (OATT) paradigm and the CAISO's organized market paradigm that should be addressed as part of the long-term framework development.**

The inconsistencies between the OATT paradigm's transmission framework and the CAISO's market design, which completely lacks physical transmission rights, create significant seams issues. The Joint California LSEs believe that the CAISO should not weaken the CAISO's market-based open access paradigm and need not seek to perfectly align its practices with those of OATT BAAs. Instead, the CAISO should strive to create a process that provides additional clarity to external parties through the CAISO's existing market structures. Through clearer rules around prioritization, the confusion and lack of certainty regarding wheeling access claimed by external entities regarding their resource planning and transacting should be alleviated. Given the different models, it is unlikely that seams issues will be fully addressed through this initiative, at least during the initial phase.

**8. Please provide comments on any other aspects of the initiative or workshop presentations.**

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

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| Order Instituting Rulemaking to Revise General Order 156 to Include Certain Electric Service Providers and Community Choice Aggregators and Encourage Voluntary Participation by Other Non-Utility Entities Pursuant to Senate Bill 255; Consider LGBT Business Enterprise Voluntary Target Procurement Percentage Goals; Incorporate Disabled Business Enterprises; Modify the Required Reports and Audits; and Update Other Related Matters. | R.21-03-010 |

# CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON STAFF PROPOSAL, WORKSHOP, AND ADDITIONAL QUESTIONS


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August 4, 2021

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## TABLE OF AUTHORITIES

## SUMMARY OF RECOMMENDATIONS

- ✓ Revise General Order (GO) 156 as set forth in Appendix A, hereto, which carves out reporting parameters for community choice aggregators (CCAs) consistent with the limited requirements of Senate Bill (SB) 255 and the restrictions on CCAs with respect to procurement;

- ✓ Hold a workshop with all parties after issuance of the Final Decision to create a CCA reporting template consistent with the revised GO 156 that better reflects CCA supplier diversity efforts;

- ✓ Expand the set of diverse suppliers in the GO 156 Clearinghouse to include small businesses from the California Department of General Services database (DGS Database); and

- ✓ Reject the Staff Proposal's recommendations to expand the requirements for CCAs outside of SB 255's directives regarding collecting data on workforce and board diversity.

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

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**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON STAFF PROPOSAL, WORKSHOP, AND ADDITIONAL QUESTIONS**

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Assigned Commissioner's Scoping Memo and Ruling* (Scoping Memo), issued on June 25, 2021, *Email Ruling Issuing Staff Proposal and Entering the Staff Proposal Into the Record* (Email Ruling), issued on July 16, 2021, *Staff Proposal to Revise General Order 156 for the Supplier Diversity Program* (Staff Proposal), issued on July 16, 2021, and the *Workshop on General Order 156 (Supplier Diversity Program)* (Workshop), held on July 21, 2021.

## I. INTRODUCTION

CCAs support the purpose of the California Public Utilities Commission's (Commission's) Supplier Diversity Program. CalCCA appreciates the opportunity to inform the Commission's

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

implementation of SB 255 through the amendment of its rules in GO 156 to, among other measures, require certain CCAs to report on supplier diversity.[2] As currently written, the Commission's Supplier Diversity Rules in GO 156 apply only to utilities, including electrical, gas, water, wireless telecommunications service providers, and telephone corporations.[3]

SB 255 extends the following two distinct requirements related to the Supplier Diversity Program to CCAs with gross annual revenues exceeding $15 million:[4]

- ✓ "[S]ubmit a detailed and verifiable ***plan*** to the commission for increasing procurement from ***small, local, and diverse business enterprises*** in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects."[5]

- ✓ "[S]ubmit a ***report*** to the Commission regarding its procurement from ***women, minority, disabled veteran, and LGBT business enterprises*** in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects."[6]

Aside from these specific and precise planning and reporting requirements, SB 255 places no other direct responsibility on CCAs in addressing CCA supplier diversity.

In fact, as recognized in the Staff Proposal and the Workshop, and as set forth more fully below, CCAs as public entities are limited by Proposition 209, which prohibits preferential treatment in public contracting "on the basis of race, sex, color, ethnicity, or national origin."[7] CCAs are also limited, and differ greatly from the IOUs who conduct procurement of a wide range of products and services, in that the vast majority of CCA procurement dollars are spent only on

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2 SB 255 SEC.1., Cal. Pub. Util Code §366.2(m).
3 General Order 156, as amended through June 11, 2015, per D.15-06-007, §1.2.
4 SB 255 SEC.1., Cal. Pub. Util Code §366.2(m).
5 *Id.*, §366.2(m)(1) (emphasis supplied).
6 *Id.*, §366.2(m)(2) (emphasis supplied).
7 California Constitution, article I, section 31, added November 5, 1996, by Prop. 209 (Proposition 209).

electricity supply, which has a relatively small pool of diverse suppliers. In addition, CCAs may be bound by restrictions in contracting by their governing authorities.

Despite these limiting factors for CCAs, however, the Supplier Diversity Reports for 2020 and Supplier Diversity Plans for 2021 submitted by the CCAs with annual gross revenue exceeding $15 million demonstrate the unique perspective, initiative, and contribution of each CCA regarding diversity in many areas, and not only in procurement.[8] The CCAs exerted tremendous effort to gather the information in the categories provided by Commission staff after the CCAs requested guidance on using existing GO 156 reporting templates (i.e., the templates applicable to investor-owned utilities (IOUs)).[9] Commission staff sent an e-mail on April 1, 2020 containing templates and a checklist explaining which GO 156 reporting categories were applicable to CCAs and which were not.[10] The CCAs are encouraged by Commission staff's willingness to adapt the existing GO 156 reporting templates (applicable to utilities) in light of SB 255 and the legal and business restrictions on CCAs. Despite the efforts to gather the information requested by the Commission, however, the CCA report templates contain many blanks or zeros as a result of the lack of applicability of the template to CCAs.

While the Staff Proposal alludes to currently established "reporting requirements" for CCAs, it should be clarified that CCAs were provided guidance on how to comply with SB 255 from Commission staff, but no formal reporting requirements were issued by the Commission.[11] Through collaborative efforts between CCAs and Commission staff, Sections 8.5, 9.1.4, 9.1.7, 10.1.3, 10.1.4, 10.1.5, and 10.1.6 of GO 156 were deemed by Commission staff to be not

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[8] The CCA Supplier Diversity Plans and Reports are available at https://www.cpuc.ca.gov/about-cpuc/consultant-and-contract-opportunities/utility-supplier-diversity-program/cca-procurement-reports.

[9] *See California Community Choice Association's Comments on Order Instituting Rulemaking to Revise General Order 156 – Supplier Diversity Program,* April 12, 2021 (CalCCA OIR Comments) at 3.

[10] *Id.* at 3 and Appendix A-2.

[11] *See* Staff Proposal at 11 (attached to Email Ruling).

applicable to CCAs.[12] Consistent with previous Commission staff guidance and the statements provided in the Staff Proposal, CalCCA urges the Commission to clarify that CCAs are not required to provide the information required in the aforementioned GO 156 sections and any other sections of GO 156 that would conflict with the Proposition 209 limitations.

To ensure the CCA Annual Plans and Reports adequately reflect the information required by SB 255 and to expand supplier diversity in electricity supply procurement, CalCCA recommends the following:

- ✓ Revise GO 156 as set forth in Appendix A, hereto, which carves out reporting parameters for CCAs consistent with the limited requirements of SB 255 and takes into consideration the factors affecting CCAs' efforts to increase supplier diversity;
- ✓ Hold a workshop with all parties after issuance of the Final Decision to create a CCA reporting template consistent with the revised GO 156 that better reflects CCA supplier diversity efforts;
- ✓ Expand the set of diverse suppliers in the GO 156 Clearinghouse to include small businesses from the DGS Database; and
- ✓ Reject the Staff Proposal's recommendations to expand the requirements for CCAs outside of SB 255's directives regarding collecting data on workforce and board diversity.

## II. REVISIONS TO GO 156 AND THE REPORTING TEMPLATES SHOULD BE TAILORED TO ENSURE CCA COMPLIANCE WITH SB 255 IN LIGHT OF THE UNIQUE CONSIDERATIONS APPLICABLE TO CCAS

GO 156, as currently written, was developed with IOUs in mind. While Commission staff attempted to tailor the existing IOU requirements to CCAs, the fact is that even with those revisions the GO 156 requirements and resulting reporting templates do not reflect the unique factors affecting CCAs with respect to diverse procurement. Accordingly, the revisions to GO 156 and the reporting templates must be tailored for CCAs to ensure compliance with SB 255 while

12 *See* CalCCA OIR Comments, Appendix A-2.

providing adequate opportunity for CCAs to present their achievements regarding diversity in procurement and elsewhere.

### A. GO 156 Revisions Concerning CCAs Must Reflect Factors Influencing CCAs' Efforts To Increase Supplier Diversity

CCAs are affected by several factors in their efforts to increase supplier diversity: (1) Proposition 209; (2) the small pool of diverse suppliers in electricity supply, for which 94 percent of CCA procurement dollars are spent; (3) state and local directives applicable to CCAs as local government entities; and (4) CCA procurement from eligible but not yet certified vendors. The sections below describe these challenges that CCAs face in expanding their diverse procurement spend.

#### 1. Proposition 209 Places Restrictions on CCAs That Do Not Apply to IOU Procurement

CCAs' support of diversity in procurement is limited by Proposition 209, which was passed as an amendment to the California Constitution on November 5, 1996.[13] Proposition 209 orders that "…the state cannot discriminate against or grant preferential treatment on the basis of race, sex, color, ethnicity, or national origin in the operation of public employment, public education, and public contracting."[14] "State" is defined to include "any city, county, city and county, . . . or any other political subdivision or governmental instrumentality of or within the state."[15] CCAs are either a program offered by a single city or county, or a Joint Powers Authority formed by multiple local governments. As such, CCAs are subject to the limitations on procurement prescribed by Proposition 209, which the Legislature acknowledged in enacting SB 255.[16]

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13 Proposition 209.

14 *Id.*

15 *Id.,* section 31(f).

16 *See* Senate Floor Analysis, Sept. 3, 2019, at 5-6, available at

CCA contract awards therefore must comply with Proposition 209 and be based upon criteria such as low bid and the ability to meet project/procurement requirements. CCAs cannot set procurement targets, such as GO 156's long-term procurement targets of not less than 15 percent for minority owned businesses and not less than five percent for women owned businesses, as currently set forth in GO 156 as it applies to IOUs.[17] Rather, CCA procurement must be complete, and the contract awarded, before a CCA can survey a vendor regarding any certification by the Commission's Supplier Diversity Clearinghouse (Commission Clearinghouse) as it relates to WMDVLGBTBE status to include such information in a CCA's Annual Report.[18] Once this information is collected, the CCA should take appropriate measures to keep this information out of any discussion of procurement to avoid violating Proposition 209.

### 2. 94 Percent of CCA Procurement Dollars Are Spent on Electricity Supply, For Which the Commission Clearinghouse Has a Relatively Small Pool of Suppliers

Nine of 14 CCAs, representing 86 percent of total procurement among all CCAs, reported their total power procurement spend in their Annual Reports. Among these nine CCAs, total spend was $2.7 billion, and total power procurement spend was $2.5 billion. Assuming this relationship holds for the remaining CCAs, roughly 94 percent – the overwhelming majority – of a CCA's

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https://trackbill.com/bill/california-senate-bill-255-women-minority-disabled-veteran-and-lgbt-business-enterprise-procurement-electric-service-providers-energy-storage-system-companies-community-choice-aggregators/1685899/ (SB Senate Floor Analysis) ("California's Proposition 209 prohibits the State from discriminating against or granting preferential treatment to any individual or group on the basis of race, sex, color, ethnicity, or national origin in the operation of public employment, public education, or public contracting. *The proposition limits the degree to which any governmental authority, including CCAs, can compel information about certain protected classes to support contract decision-making.")* (Emphasis added).

[17] GO 156, Section 8.2.

[18] *See* SB Senate Floor Analysis, at 6 ("The proposition limits the degree to which any governmental entity within California, including CCAs, can compel information about certain protected classes to support contract decision-making. However, the Proposition does not prohibit after-the-fact reporting on outcomes from contracting. [SB 255] requires CCAs to develop plans for small, local, and diverse business contracting; however, it requires CCAs to report after-the-fact on contracting with WMDVLGBTBEs.").

annual procurement dollars go to power procurement. Unlike IOUs whose spending is focused largely on infrastructure and represents the spending of a large corporation, the CCA focus is on electric generation for local communities, resulting in limited categories of procurement.

As set forth in CalCCA's OIR Comments, Appendix A-1, a review of the Commission Clearinghouse reveals that power procurement has a very small pool of qualifying WMDVLGBTBE suppliers.[19] Of the roughly 8,800 suppliers in the Commission Clearinghouse, only 27 (0.003%) could be identified as relating to electricity generation.[20] Given the small pool of suppliers of power, it is very challenging for all load-serving entities (LSEs), including CCAs, to increase diverse power procurement spend.

In addition, GO 156 compliance is determined exclusively through procurement from the Commission Clearinghouse. However, CCAs engage in diverse spending beyond the Commission Clearinghouse. As set forth below, CalCCA provides recommendations regarding increasing the number of diverse providers in the Commission Clearinghouse with vendors and contractors who (1) are included in the DGS Database and should be incorporated into the Commission Clearinghouse, or (2) may be eligible for GO 156 certification but may not know how to navigate the certification process.

#### 3. CCAs May Be Subject to State and Local Directives That Impact Procurement

As local governments, CCAs set procurement policies consistent with the direction of their Boards, which consist of elected representatives from their member jurisdictions. Consequently, different CCAs may have varying policies, which often include bidding and contract award

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19 CalCCA OIR Comments at 6, and Appendix A-1.

20 *Id.*

requirements that may vary from existing GO 156 requirements and should be acknowledged in the revisions regarding CCA reporting. Examples of these policies include:

- Selection of the "lowest responsible bidder" – meaning the bidder who best responds in price, quality, service, fitness, or capacity to the requirements;
- Local preference to support businesses that are located within or near the CCA's service territory;
- Procurement from certified small businesses and micro businesses recognized in the DGS Database; and
- Preference for union labor.[21]

CCA governing authorities thus provide additional requirements for CCAs in their procurement that must be incorporated in the revisions to GO 156.

**B. GO 156 Revisions Should Include a Section Specifically Applicable to CCAs, Rather Than Applying the Existing IOU Requirements to CCAs**

Appendix A, hereto, provides a new Section 12 for GO 156 that provides categories of information to be provided by CCAs in their Annual Plans and Annual Reports in compliance with the directives of SB 255 and Public Utilities Code section 366.2(m). The Annual Plans look forward to the next year and require information regarding CCAs "increasing procurement from small, local, and diverse business enterprises in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects."[22] The Annual Reports look back at the prior year and require information regarding CCA "procurement from women, minority, disabled veteran, and LGBT business enterprises in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects."[23] The following

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[21] East Bay Community Energy (EBCE) Supplier Diversity 2020 Annual Report & Annual Plan at 12; Peninsula Clean Energy Authority 2020 Annual Report & 2021 Annual Plan, Appendix B: Policy #10 *Inclusive and Sustainable Workforce Policy,* at 18; Sonoma Clean Power Supplier Diversity 2020 Annual Report & 2021 Annual Plan, *Policy Barriers to More Effective GO 156 Results* at 33.

[22] Cal. Pub. Util. Code §366.2(m)(1).

[23] *Id.*, §366.2(m)(2).

provides the categories included in the proposed Section 12 regarding CCAs for both the Annual Plans and Annual Reports. These categories were created from the checklists provided by Commission staff based on provisions of GO 156 applicable to CCAs.

**1. CCA Annual Plans**

As set forth in section 12 of Appendix A, hereto, containing proposed revisions to GO 156 regarding CCAs, categories of information to be provided by CCAs in their Annual Plans may include, but not be limited to, the following:

- Description of program activities to increase CCA procurement related to small, local, and diverse business enterprises planned for the next year in all categories, including, but not limited to, renewable energy, energy storage systems, and smart grid projects.
- Short and long-term goals regarding increasing procurement related to small, local, and diverse business enterprises, broken down by product and service categories.

**2. CCA Annual Reports**

As set forth in section 12 of Appendix A, hereto, containing proposed revisions to GO 156 regarding CCAs, categories of information to be provided by CCAs in their Annual Reports may include, but not be limited to, the following:

- Summary of WMDVLGBTBE, and small, local and diverse business enterprise, purchases and/or contracts in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects, with breakdowns to the extent possible compared with total purchases or contract dollars awarded:
  - By ethnicity;
  - By product and service categories;
  - Total number of WMDVLGBTBEs, and small, local and diverse business enterprises, with contracts;
  - Dollars awarded to WMDVLGBTBEs, and small, local and diverse business enterprises; and
  - Number of WMDVLGBTBEs, and small, local and diverse enterprises, that received direct spend.

- A description (to the extent possible) of the WMDVLGBTBEs, and small, local and diverse business enterprises, which were awarded purchases and/or contracts who have the majority of their workforce working in California.
    - Awards by prime contractors to verified WMDVLGBTBE, and small, local and diverse business enterprise, subcontractors.
    - A list, description, and status of WMDVLGBTBE, and small, local and diverse business enterprise, complaints.
    - An itemization of program expenses related to GO 156 compliance.

### C. A Workshop Should Be Held To Create a CCA Specific Reporting Template Subsequent to the Final Decision's Adoption of the Revised GO 156

After the adoption of these revisions to GO 156 in the Final Decision, CalCCA proposes that a workshop be held to draft and develop reporting templates unique to CCAs that are consistent with the revised GO 156 and enable CCAs to adequately represent their progress regarding diversity.

## III. THE POOL OF DIVERSE SUPPLIERS LISTED AS QUALIFIED VENDORS FOR ELECTRICITY SUPPLY IN THE COMMISSION CLEARINGHOUSE MUST BE EXPANDED

In addition to revising GO 156 to more accurately reflect CCA activities and progress regarding supplier diversity, the revisions to GO 156 should expand the list of diverse suppliers that can be included in CCA reports to include the full DGS Database.[24] The DGS Database provides access for CCAs to small and local businesses, consistent with the requirements of section 366.2(m)(1) of the Public Utilities Code and in furtherance of CCA efforts to support these small and local businesses facing economic strain during the COVID-19 pandemic.

In addition, CCAs have been confronted with suppliers that could be certified under the Commission Clearinghouse but may be unaware of it or are unable to navigate the certification

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[24] A search tool for diverse business is available at the following address: https://caleprocure.ca.gov/pages/PublicSearch/supplier-search.aspx.

process. For those suppliers, several CCAs have committed to supporting their eligible but non-GO 156 certified contractors in obtaining certification.[25]

## IV. THE SCOPING MEMO AND STAFF PROPOSAL'S ADDITION OF WORKFORCE AND BOARD DIVERSITY REPORTING REQUIREMENTS ARE OUTSIDE THE SCOPE OF SB 255'S DIRECTIVES AND SHOULD BE REJECTED

A requirement that CCAs report on workforce and board diversity is beyond the scope of SB 255, and any such reporting should only be provided voluntarily by CCAs. The Scoping Memo asks whether GO 156 should be revised "to include economic impact of the Supplier Diversity Program and work force and corporate board diversity data."[26] The Staff Proposal also states that "the Commission is considering whether to collect data on workforce and corporate board diversity from GO 156 participants, including . . . [CCAs] . . . ."[27] SB 255, however, provides very limited authority to the Commission regarding including CCAs in the Supplier Diversity Program. The Commission is not permitted by SB 255 to expand its authority over CCAs by incorporating CCA workforce and board diversity reporting requirements in GO 156, and therefore the proposed addition of such requirements to GO 156 should be rejected.[28]

While such requirements should not be incorporated into GO 156, CCAs do recognize the importance of such information. In fact, some CCAs have voluntarily included information regarding workforce and board diversity in their Annual Plans and Reports, to the extent permitted by law. For example, Clean Power Alliance provided staff diversity data based on voluntary self-reporting in its 2020-2021 Annual Report & Plan and expects to collect board diversity data from

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[25] *See* EBCE Supplier Diversity 2020 Annual Report & 2021 Annual Plan at 8 (stating EBCE's commitment to offer eligible vendors support in their pursuit of certification in the Commission Clearinghouse).

[26] Scoping Memo at 7.

[27] Staff Proposal at 11.

[28] Proposition 209 also prohibits CCAs from enforcing workforce diversity, and CCA board members are elected officials and CCAs have no role in selecting them.

voluntary surveys beginning in 2021.[29] In addition, Sonoma Clean Power provided information on its internal policies focusing on diversity and equity in its 2020 Annual Report and 2021 Annual Plan.[30]

## V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the recommendations herein.

Respectfully submitted,

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

August 4, 2021

[29] Clean Power Alliance Supplier Diversity 2020 Annual Report & 2021 Annual Plan at 7-8.
[30] Sonoma Clean Power Supplier Diversity 2020 Annual Report & 2021 Annual Plan at 5-10.

## APPENDIX A: GO 156 REVISIONS (IN REDLINE)

1.1 Intent

Purpose – These rules implement California Public Utilities Code (Code) sections 8281-8286 which require the Commission to establish a procedure for the electrical, gas, water, wireless telecommunications service provider, and telephone corporation with gross annual revenues exceeding twenty-five million dollars ($25,000,000) and their commission-regulated subsidiaries and affiliates to submit annual detailed and verifiable plans for increasing women-owned, minority-owned, disabled veteran-owned and LGBT-owned business enterprises' (WMDVLGBTBEs) procurement in all categories. These rules also implement Code section 366.2(m) which requires the Commission to establish a procedure for Community Choice Aggregators (CCAs) with gross annual revenues exceeding fifteen million dollars ($15,000,000) to (1) submit a plan to the Commission for increasing procurement from small, local, and diverse business enterprises in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects, and (2) to submit a report in a form and on a date set forth by the commission regarding a CCA's procurement from women, minority, disabled veteran, and LGBT business enterprises, in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects.

1.2 Applicability

These rules apply to all electrical, gas, water, wireless telecommunications service provider, and telephone corporation with gross annual revenues exceeding twenty-five million dollars ($25,000,000) and their commission-regulated subsidiaries and affiliates. The Rules herein applicable to Community Choice Aggregators (CCAs) with gross annual revenues exceeding fifteen million dollars ($15,000,000) are limited to Sections 1-5, 7, 11-12, only. Rules 6, 8-10 do not apply to CCAs.

1.3 Definitions

1.3.25. "CCA" means a Community Choice Aggregator as defined in section 331.1 of the California Public Utilities Code.

11. Commission Report

The Commission shall provide an annual report to the Legislature beginning in January, 1989, on the progress of activities undertaken by each utility to implement Public Utilities Code sections 8281 through 8286 and this General Order, as required by Section 8283(e). The Commission shall provide as part of its annual report a section applicable only to CCAs, which includes the information provided in the Annual Plans and Annual Reports provided by CCAs pursuant to Public Utilities Code sections 366.2(m)(1) and 366.2(m)(2), and Rule 12 herein.

11.2 This report shall include recommendations to the utilities and CCAs for the achievement of maximum results in implementing legislative policy and this General Order.

11.3 The Commission shall hold an annual en banc hearing or other proceeding in order to provide utilities, CCAs, and members of the public, including community-based organizations, the opportunity to share ideas and make recommendations for effectively implementing legislative policy and this General Order.

**12 CCAS**

12.1 Annual Plan.

12.1.1 Each CCA to which these Rules apply shall serve an electronic copy on the Executive Director, by March 1 of each year, an Annual Plan in accordance with Public Utilities Code section 366.2(m)(1). The Annual Plan shall contain a detailed and verifiable plan for increasing procurement from small, local, and diverse business enterprises in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects.

12.1.2 The Annual Plan may also include, but not be limited to, the following elements:

12.1.2.1 Description of program activities to increase CCA procurement related to small, local, and diverse business enterprises planned for the next year in all categories, including, but not limited to, renewable energy, energy storage systems, and smart grid projects.

12.1.2.2 Short and long-term goals regarding increasing procurement related to small, local, and diverse business enterprises, broken down by product and service categories.

12.2 Annual Report

12.2.1 Each CCA to which these Rules apply shall serve an electronic copy on the Executive Director, by March 1 of each year, an Annual Report in accordance with Public Utilities Code section 366.2(m)(2). The Annual Report shall contain information regarding the CCA's procurement from women, minority, disabled veteran, LGBT, and small, local and diverse, business enterprises, in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects. The Annual Report shall include women, minority, disabled veteran, LGBT, and small, local and diverse, business enterprises, with whom a prime contractor or grantee of a CCA has engaged in contracts or subcontracts for all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects.

12.2.2 The Annual Report may also include, but not be limited to, the following elements:

12.2.2.1 Summary of WMDVLGBTBE, and small, local and diverse business enterprise, purchases and/or contracts in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects, with breakdowns to the extent possible compared with total purchases or contract dollars awarded:

(i) By ethnicity

(ii) By product and service categories

(iii) Total number of WMDVLGBTBEs and small, local and diverse business enterprises, with contracts

(iv) Dollars awarded to WMDVLGBTBEs and small, local and diverse business enterprises

(v) Number of WMDVLGBTBEs and small, local and diverse business enterprises, that received direct spend.

12.2.2.2 A description (to the extent possible) of the WMDVLGBTBEs, and small, local and diverse business enterprises, which were awarded purchases and/or contracts who have the majority of their workforce working in California.

12.2.2.3 Awards by prime contractors to verified WMDVLGBTBE, and small, local and diverse business enterprise, subcontractors.

12.2.2.4 A list, description, and status of WMDVLGBTBE, and small, local and diverse business enterprise, complaints.

12.2.2.4 An itemization of program expenses related to GO 156 compliance.

# Submit comment on July 27 stakeholder call discussion

2021-2022 Transmission planning process

**1. Provide a summary of your organization's comments on the July 27, 2021 stakeholder call discussion:**

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the presentations from the July 27, 2021 stakeholder call. Forward planning and coordination between the CAISO, California Public Utilities Commission (Commission), and the California Energy Commission (CEC) will play a critical role in ensuring California can meet its ambitious climate goals reliably and cost effectively. Transmission planning is a major piece of this coordination, and the CAISO must approve transmission projects far enough in advance to accommodate the influx of clean resources that will come online to meet Senate Bille (SB) 100 targets. The 20-year Transmission Outlook should inform transmission planning that results in approval of projects far enough in advance to reliably meet climate goals.

**2. Provide your organization's comments on the transmission capability information provided to the California Public Utilities Commission through its Integrated Resource Planning Process, as described in slides 4-28:**

CalCCA supports the CAISO's efforts updating the transmission capability estimates used in the Integrated Resource Planning (IRP) Process and appreciates the collaborative effort between the CAISO and the Commission. Coordination between the CAISO and the Commission is crucial to ensure transmission and resource build can reliably meet climate goals.

**3. Provide your organization's comments on the Policy-driven Assessment Sensitivity 1 – Offshore Wind Studies topic, as described in slides 29-50 related to the 2021-2022 Transmission Planning Process:**

No comments at this time.

**4. Provide your organization's comments on the Economic Assessment Assumption Update for 2021-2022 Planning Cycle topic, as described in slides 51-65 related to the 2021-2022 Transmission Planning Process:**

The CAISO's presentation indicates their model will assume co-located storage resources can charge from the grid, noting this will result in a loss of investment tax credit dollars for the resource owner. The CAISO should reconsider whether this assumption appropriately reflects how storage resources will operate given the significant cost impact grid charging has on resource owners eligible for the investment tax credit.

**5. Provide your organization's comments on the Out of State Wind In Portfolios topic, as described in slides 66-73 related to the 2021-2022 Transmission Planning Process:**

CalCCA is encouraged that the CAISO plans to perform a special study on out-of-state wind transmission alternatives. The CAISO, Commission, and CEC should consider these out-of-state transmission projects in the context of both IRP and Transmission Planning Process (TPP) processes to understand how each project enhances California's ability to access clean and renewable resources in the most cost effective and reliable way to meet SB 100 goals. In particular, resource profiles for out-of-state wind appear attractive when looking at potential resource output during critical hours but the CAISO, the Commission, and the CEC should also consider IRP cost assumptions and individual load-serving entities IRP reporting to determine whether or not such resources are selected in IRP modeling.

Any such consideration of out-of-state wind, or other out-of-state resources should be evaluated with cost effectiveness in mind. The results of the TPP should not simply find resources that are attractive but will never be built and imported due to cost constraints while building transmission in anticipation of such resources. Modeling of the need and the costs of alternatives will therefore play a critical role in this process.

**6. Provide your organization's comments on the updates related to the 20-Year Transmission Outlook, as described in slides 74-84:**

CalCCA appreciates the CAISO's efforts to develop the 20-year Transmission Outlook and commends the CAISO for its collaboration with the Commission and the CEC in the IRP, SB 100, and Integrated Energy Policy Report (IEPR) processes. Coordination with these processes will ensure resource procurement and new transmission build aligns. Forward planning with a long enough lead time will be critical in ensuring the state is prepared to meet SB 100 goals that require renewable energy and zero-carbon resources to supply 100 percent of electric retail sales to end-use customers by 2045. The CAISO should consider how the 20-year Transmission Outlook could be incorporated into the existing Transmission Planning Process (TPP) to consider what transmission build will need to occur and in what timeframe to meet policy goals. Given the time required develop new transmission, the 10-year look ahead in the TPP can result in transmission projects coming online just in time to meet an identified reliability need.

CalCCA is encouraged that the 20-year Transmission Outlook will utilize the SB 100 "No Combustion" scenario for 2040. Recognizing that decarbonization goals necessitate significant resource build, it is prudent to use this scenario to inform potential transmission projects so that new clean resources do not get stranded behind transmission constraints. Considering the large number of resources expected to come online to meet state policies, the TPP could benefit from the insight of a longer planning horizon provided by the 20-year Transmission Outlook to inform policy-driven transmission projects. The 20-year Transmission Outlook should be used to inform the TPP of transmission needs driven by clean energy policies like SB 100 so that projects approved in the TPP also contribute to meeting policy goals that will be realized beyond 10 years out.

CalCCA also supports the 20-year Transmission Outlook's consideration of key environmental and land use impacts provided by the CEC. Land use and habitat concerns can create serious delays or project cancellations if not incorporated into site evaluation from the start. By incorporating these considerations into transmission planning, the CAISO, the Commission, and the CEC can help steer projects to less sensitive areas and avoid potentially serious delays or cancellations of transmission projects needed to integrate future resource procurement.

**7. Additional comments on the July 27, 2021 stakeholder call discussion:**

No additional comments at this time.

# Submit comment on Issue paper and working group discussion

Initiative: Energy storage enhancements

### 1. Please provide a summary of your organization's general comments on the working group presentations and the scope of issues for this initiative:

California Community Choice Association (CalCCA) appreciates the opportunity to submit comments on parties' presentations during the Energy Storage Enhancements working group. As storage resources continue to make up an increasing portion of the resource mix, it will be critical to ensure the market can utilize this unique resource in an efficient and reliable manner.

CalCCA offers the following comments on the working group presentations:

- CalCCA supports NGR modeling and bidding parameter enhancements to include operational characteristics of new technologies and to allow for reflection of marginal costs as a function of cycling or state-of-charge;
- The CAISO should demonstrate existing market signals are not sufficient and create a need for a new market product to ensure state-of-charge product before proposing a replacement to the minimum state of charge requirement; and
- CalCCA supports the CAISO providing advisory real-time price data transparency such that scheduling coordinators (SCs) have more information about potential prices in later intervals.

### 2. Provide your organization's comments on the presentations provided by stakeholders at the working group:

**NGR Model and Bidding Parameter Enhancements**

CalCCA supports enhancements to the NGR model and bidding parameters to include operational characteristics of new technologies and to allow for reflection of marginal costs as a function of cycling or state-of-charge. WPTF's presentation indicated that long duration storage technologies have unique operational characteristics that require additional bidding parameters, including transition times, start-up times, and multiple ramp rates.[1] Modeling resources' operational characteristics correctly ensures the market dispatches them consistent with their physical operating capability.

CalCCA also supports bidding parameter enhancements to allow resources to better reflect marginal costs in their bids. CESA and GDS Associates discussed two potential enhancements to storage bidding functionality that would better reflect marginal costs, which can vary subject to state-of-charge and cycling levels. The first would allow storage resources to submit multiple bid curves to reflect marginal costs as a function of state-of-charge or cycle. The second would allow storage

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1 WPTF Presentation, July 26, 2021, at 5: http://www.caiso.com/InitiativeDocuments/WPTFPresentation-EnergyStorageEnhancementsWorkingGroup-Jul26-2021.pdf.

resources to submit updates to their bids closer to the dispatch interval to reflect changes to state-of-charge or cycle. Either approach will improve storage resources' ability to reflect marginal costs most accurately, enabling more efficient market operation.

In addition to bidding parameter enhancements, the CAISO should seek additional understanding about marginal costs for new storage technologies in order to represent them accurately. The CAISO should seek input from the Department of Market Monitoring (DMM) and storage resource owners about how to quantify such marginal costs. Additionally, the CAISO should consult with load serving entities (LSEs) contracting with storage resources as marginal costs are likely currently reflected through the contracts between LSEs and resources given marginal costs cannot yet be fully reflected in bids.

**Ensuring State-of-Charge**

Several parties discussed how to ensure storage resources are charged and available to provide energy when needed. PG&E presented a state-of-charge firming ancillary service product.[2] CESA highlighted modifications the CAISO could make including a longer real-time look ahead, scarcity pricing, an energy shift product, and a biddable state-of-charge product.[3] GDS Associates[4] and WPTF suggested market prices should ensure storage resource availability during times of greatest system need.[5] While storage resources are and will continue to be a key contributor to system reliability, it is not clear the market requires an additional product to preserve state-of-charge to ensure storage resource availability.

The CAISO should demonstrate existing market signals are not sufficient and create a need for a new market product to ensure state-of-charge product before proposing a replacement to the minimum state of charge requirement. The CAISO has expressed significant concern about the potential for the day-ahead market to schedule storage to meet net load peaks only to have this schedule undone by real-time market resulting in reliability concerns. However, this scenario has not yet proven to be a systemic issue and ignores the fact that storage resource will respond to price signals in a way that maximizes their profits. It also introduces a new reliability concern in which the CAISO constrains a resource's flexibility so it is unable to respond to another reliability event, such as a contingency in a local area. Before proposing a new product to ensure state-of-charge that restricts storage resources' flexibility, the CAISO should analyze recent battery market participation to evaluate if storage discharging at inopportune times is a systemic issue that needs to be addressed by a new product. If market prices provide appropriate signals that reflect grid needs, resource providers will make the best decisions on how to address such needs to maximize profit. The CAISO has not yet demonstrated that market prices do not provide sufficient incentive for storage resources to be charged for the most critical hours and as GDS Associates notes, it is not clear why the market would manage storage resources differently from other use-limited resources.

Prior to proposing a new product, the CAISO should first identify a need for one exists by evaluating recent storage resource participation to determine if they systemically discharge during times that adversely impact reliability. The CAISO should specifically consider storage participation during this summer, given the significant amount of storage that has come online in recent months.

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[2] http://www.caiso.com/InitiativeDocuments/PG-EPresentation-EnergyStorageEnhancementsWorkingGroup-Jul26-2021.pdf

[3] http://www.caiso.com/InitiativeDocuments/CESAPresentation-EnergyStorageEnhancementsWorkingGroup-Jul26-2021.pdf

[4] http://www.caiso.com/InitiativeDocuments/GDSPresentation-EnergyStorageEnhancementsWorkingGroup-Jul26-2021.pdf

[5] http://www.caiso.com/InitiativeDocuments/WPTFPresentation-EnergyStorageEnhancementsWorkingGroup-Jul26-2021.pdf

**Publishing Advisory Price Data**

CalCCA supports the CAISO providing advisory real-time price data transparency such that scheduling coordinators (SCs) have more information about potential prices in later intervals. Publishing advisory real-time price data would provide beneficial information about expected prices later in the day to allow storage resources to make better informed decisions about if and when to deviate from their day-ahead award when real-time prices are trending significantly higher than day-ahead prices. With advisory price data, storage resources will be able to better determine if the high prices in real-time will be sustained throughout the day or due a temporary price spike. If high prices are sustained throughout the day, it may be more profitable for the resource and reliable for the system for the resource to wait until the net peak to discharge. If a price spike is to address a temporary reliability need, it may be more profitable for the resource and reliable for the system for the resource to deviate from its day-ahead schedule to meet a temporary reliability need. Access to advisory price information will allow storage resources to better assess reliability needs of the grid in the absence of a longer real-time market look-out horizon.

**3. Provide any additional comments on the working group, or any additional scope items your organization feels should be included for this initiative. You may upload examples and data using the "attachments" field below:**

No additional comments at this time.

**COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE CALIFORNIA ENERGY COMMISSION ON THE JOINT AGENCY WORKSHOP ON NEXT STEPS TO PLAN FOR SENATE BILL 100 RESOURCE BUILD: TRANSMISSION**
**July 22, 2021**

**Docket Number 21-SIT-01**
**SB 100 Implementation: Planning for SB 100 Resource Build**

The California Community Choice Association[1] (CalCCA) submits these comments to the California Energy Commission (Commission) in Docket Number 21-SIT-01 on the *Joint Agency Workshop on Next Steps to Plan for Senate Bill 100 Resource Build: Transmission*, held July 22, 2021.

## I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the Joint Agency Workshop on Next Steps to Plan for Senate Bill 100 Resource Build: Transmission. Forward planning and coordination between the California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and the Commission (Joint Agencies) will play a critical role in ensuring California can meet its ambitious climate goals reliably and cost effectively.

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

Transmission planning is a major piece of this coordination, and the Joint Agencies must work together to ensure transmission projects are built far enough in advance to accommodate the influx of clean resources that will come online to meet Senate Bill (SB) 100 targets that require renewable energy and zero-carbon resources supply 100 percent for electric retail sales to end-use customers by 2045.

## II. COMMENTS

Collaboration between the Joint Agencies in the Integrated Resource Planning (IRP), SB 100, and Transmission Planning processes will ensure resource procurement and new transmission build aligns. The CPUC noted in their presentation that California is, "Beginning to see a shift from an era of available transmission headroom to one where transmission development will be necessary to accommodate the large amounts of resources expected to come online in the next 10 - 20 years to meet state goals."[2] Transmission projects driven by such state goals should be informed by the 20-year Transmission Outlook presented by the CAISO, which looks over a longer horizon than the CAISO's annual Transmission Planning Process (TPP) which addresses a 10-year planning horizon. Given the time required to develop new transmission, the 10-year look ahead in the TPP can result in transmission projects coming online just in time to meet an identified reliability need. CalCCA is encouraged that the 20-year Transmission Outlook will utilize the SB 100 "No Combustion" scenario for 2040. Recognizing that decarbonization goals necessitate significant resource build, it is prudent to use this scenario to inform potential transmission projects so that new clean resources do not get stranded behind transmission constraints. Considering the large number of resources expected to come online to meet state policies, the TPP, IRP, and SB 100 initiatives could benefit from the insight of a

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[2] CPUC presentation at 19: https://www.energy.ca.gov/sites/default/files/2021-07/July%2022%20Workshop%20SB%20100%20Transmission_Master%20v4.pdf

longer planning horizon provided by the 20-year Transmission Outlook to inform policy-driven transmission projects.

CalCCA is encouraged by the presentations during the workshop on in-state and out-of-state transmission projects that could enhance California's ability to access off-shore and out-of-state wind. The Joint Agencies should consider these transmission projects in the context of IRP and TPP processes to understand how each project enhances California's ability to access clean and renewable resources in the most cost effective and reliable way to meet SB 100 goals. In particular, resource profiles for out-of-state wind appear attractive when looking at potential resource output during critical hours but the Joint Agencies should also consider IRP cost assumptions and individual load-serving entity IRP reporting to determine whether or not such resources are selected in IRP modeling.

CalCCA also supports the Commission's consideration of key environmental and land use impacts in transmission planning. Land use and habitat concerns can create serious delays or project cancellations if not incorporated into site evaluation upfront. By incorporating these considerations into transmission planning, the CAISO and the Joint Agencies can help steer projects to less sensitive areas and avoid potentially serious delays or cancellations of transmission projects needed to integrate future resource procurement.

## III. CONCLUSION

CalCCA appreciates Commission staff's efforts in evaluating transmission needs to meet SB 100 goals.

Dated: August 11, 2021

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Director of Regulatory Affairs
**California Community Choice Association**
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**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access. | R.19-03-009 |

# RESPONSE OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE APPLICATION OF THE ALLIANCE FOR RETAIL ENERGY MARKETS, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, DIRECT ACCESS CUSTOMER COALITION, ENERGY PRODUCERS AND USERS COALITION, SHELL ENERGY NORTH AMERICA (US), L.P. AND WESTERN POWER TRADING FORUM FOR REHEARING OF DECISION 21-06-033

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August 13, 2021

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

| | |
|---|---|
| Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access. | R.19-03-009 |

**RESPONSE OF**
**CALIFORNIA COMMUNITY CHOICE ASSOCIATION**
**TO THE APPLICATION OF THE ALLIANCE FOR RETAIL ENERGY MARKETS, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, DIRECT ACCESS CUSTOMER COALITION, ENERGY PRODUCERS AND USERS COALITION, SHELL ENERGY NORTH AMERICA (US), L.P. AND WESTERN POWER TRADING FORUM FOR REHEARING OF DECISION 21-06-033**

Pursuant to California Public Utilities Commission's (Commission) Rule of Practice and Procedure (Rule) 16.1(d), the California Community Choice Association (CalCCA)[1] submits this Response to the *Application of The Alliance for Retail Energy Markets, California Large Energy Consumers Association, Direct Access Customer Coalition, Energy Producers and Users Coalition, Shell Energy North America (US), L.P. and Western Power Trading Forum (Applicants) for Rehearing of Decision 21-06-033*, filed July 29, 2021 (Application). The Decision Recommending Against Further Direct Access Expansion, D.21-06-033 (Decision), was voted out by the Commission on July 24, 2021, and issued on July 29, 2021.

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

## I. INTRODUCTION

Applicants seek rehearing of the Decision recommending against future expansion of Direct Access based on the Commission's inability to make the findings required by California Public Utilities Code section 365.1(f)(2), enacted by Senate Bill (SB) 237 (2018). The Decision thoroughly considered the implications of reopening Direct Access consistent with the Legislature's requirements set forth in SB 237. The Commission clearly explained that the Decision was issued "against the backdrop of two recent grid reliability events" in the summer of 2020, and the forecasts from the Commission's Integrated Resource Planning (IRP) proceeding demonstrating the significant capacity deficits that California faces.[2] The Commission is currently scrambling to ensure electric system reliability in the near- and long-term. The Decision therefore came at a time in which the Commission's priorities – maintaining grid reliability, ensuring adequate capacity, and complying with the State's ambitious greenhouse gas emission reduction goals – resulted in its findings recommending against reopening Direct Access.

Applicants contend: (1) that the Commission misinterpreted its statutory duties under SB 237, thus abusing its discretion; (2) that the Commission's findings are not based on substantial evidence; and (3) that Applicants are unfairly discriminated against in violation of the dormant Commerce Clause and the Equal Protection Clause of the Federal and State Constitutions.

The Commission's determinations and legal conclusions set forth in the Decision are correct, and the Application for Rehearing should be denied for the following reasons:

- ✓ The Commission's interpretation of section 365.1(f)(2) is consistent with the plain language of the entire statute, as well as the legislative history of SB 237, and therefore the Commission proceeded in the manner required by law and did not abuse its discretion.

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[2] Decision at 2-4.

- ✓ The Decision is supported by the findings required by California Public Utilities Code section 365.1(f)(2) and is also adequately supported by findings based on the entire administrative record of the proceeding. Specifically, the Commission determined based on the record that it could not make the required findings under section 365.1(f)(2), and therefore could not recommend the reopening of Direct Access.

- ✓ Applicants' dormant Commerce Clause argument fails because the Decision applies equally to both in-state and out-of-state Electric Service Providers (ESPs) and therefore does not unfairly discriminate against out-of-state interests.

- ✓ Applicants' argument that the Decision discriminates against both ESPs and their customers and therefore violates their Equal Protection rights fails the "rational basis" test in that the Decision is based on the findings regarding electric grid reliability and environmental concerns.

## II. DISCUSSION

### A. Legal Standard

Under Rule 16.1, "the purpose of an application for rehearing is to alert the Commission to a legal error, so that the Commission may correct it expeditiously."[3] An application for rehearing "shall set forth specifically the grounds on which the applicant considers the order or decision of the Commission to be unlawful or erroneous, and must make specific references to the record or law."[4] While a party may not agree with the outcome in a highly contested proceeding, "[a]n application for rehearing should raise legal error, and should not be used as a vehicle for relitigation of policy positions or to reweigh evidence."[5]

Under California Public Utilities Code section 1757.1, the Commission commits legal error when: (1) the decision was an abuse of discretion; (2) the Commission has not proceeded in the manner required by law; (3) the Commission acted without, or in excess of, its powers or

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3 Rules of Practice and Procedure, Rule 16.1(c) (emphasis added).
4 *Id.*
5 *Order Denying Application for Rehearing of Decision 19-10-056,* Rulemaking (R.) 19-07-017, Mar. 2, 2020 at 4 ("the application for rehearing essentially repeats verbatim the arguments raised in [Applicant's] comments to the Proposed Decision," and "[t]he fact that we did not weigh the evidence in [Applicants'] favor does not constitute legal error").

jurisdiction; (4) the decision is not supported by the Commission's findings; (5) the decision was procured by fraud; or (6) the decision violates any right of the petitioner under the Constitution of the United States or the California Constitution.[6]

Upon review, courts defer generously to the Commission's judgment in carrying out the legal powers and responsibilities delegated to the Commission by the State Constitution and applicable statutes.[7] "There is a strong presumption of validity of the Commission's decisions, . . . and the Commission's interpretation of the California Public Utilities Code should not be disturbed unless it fails to bear a reasonable relation to statutory purposes and language . . . ."[8] Courts give "presumptive value to a public agency's interpretation of a statute within its administrative jurisdiction because the agency may have 'special familiarity with satellite legal and regulatory issues,' leading to expertise expressed in its interpretation of the statute."[9] In addition, when conflicting inferences can reasonably be drawn from the facts, the weighing of factors by the Commission is a matter within the exclusive jurisdiction of the Commission.[10]

### B. The Commission's Interpretation of SB 237 Does Not Constitute Legal Error or an Abuse of Discretion

Applicants contend that the Commission disregarded the "express duties imposed on it by SB 237" and abused its discretion by failing to provide a recommendation to reopen Direct Access.[11] Applicants' argument, however, fails on many levels. As a threshold matter, as described above, the Commission's interpretation of the California Public Utilities Code is given

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[6] Cal. Pub. Util. Code §1757.1(a).

[7] California Constitution, Art. XII, §§1-6; Cal. Pub. Util. Code §§701, 1701(a).

[8] *Greyhound Lines, Inc. v. Public Utilities Comm'n* (1968) 68 Cal.2d 410, 410-11 (citations omitted).

[9] *Pacific Gas and Electric Co. v. Public Utilities Comm'n* (2015) 237 Cal.App.4th 812, 839 (citing *Pacific Bell Wireless, LLC v. Public Utilities Comm'n* (2006) 140 Cal.App.4th 718, 729).

[10] *Pacific Gas and Electric Co.,* 237 Cal. App.4th at 838-839 (citations omitted).

[11] Application at 3.

great deference.[12] Furthermore, Applicants improperly interpret and apply one part of SB 237 in isolation from the rest of the statute. Finally, even if the language of SB 237 permits more than one reasonable interpretation, legislative history associated with SB 237 firmly supports the Commission's interpretation.

### 1. The Commission's Interpretation of SB 237 is Lawful and Within its Expertise and Discretion

Applicants cite to only one part of SB 237 in concluding that the Commission "disregarded" the "express directives" of SB 237:

> On or before June 1, 2020, the commission shall provide recommendations to the Legislature on implementing a further direct transactions reopening schedule, including, but not limited to, the phase-in period over which the further direct transactions shall occur for all remaining nonresidential customer accounts in each electrical corporation's service territory.[13]

By citing the above section in isolation, without the statutory language surrounding it, Applicants claim that the Commission "unlawfully elected to issue a Decision that failed to comply with the duties imposed on it by the precise and explicit wording of SB 237."[14] However, a closer examination of the requirements imposed on the Commission establish that the Commission's obligation in SB 237 extends beyond Applicants' characterization of that obligation.

Through SB 237, the Legislature directs the Commission to act on Direct Access in two phases: (1) to reopen Direct Access on a limited basis by June 1, 2019, and (2) with regard to further reopening (at issue in the current Application), to provide recommendations to the Legislature.[15] With respect to the first phase, SB 237 provides:

> (e) On or before June 1, 2019, the commission shall issue an order regarding direct transactions that provides as follows:

[12] *See Greyhound,* 68 Cal.2d at 410-11.
[13] Cal. Pub. Util. Code §365.1(f)(1).
[14] Application at 5.
[15] Cal. Pub. Util. Code §§365.1(e), (f).

> (1) Increase the maximum allowable total kilowatthours annual limit by 4,000 gigawatthours and apportion that increase among the service territories of the electrical corporations,
> (2) All residential and nonresidential customer accounts that are on direct access as of January 1, 2019, remain authorized to participate in direct transactions.[16]

With respect to the second phase, SB 237 requires:

> (f)(1) On or before June 1, 2020, the commission shall provide recommendations to the Legislature on implementing a further direct transactions reopening schedule including, but not limited to, the phase-in period over which the further direct transactions shall occur for all remaining nonresidential customer accounts in each electrical corporation's service territory.
> (2) In developing the recommendations pursuant to paragraph (1), the commission shall find all of the following:
> (A) The recommendations are consistent with the state's greenhouse gas emission reduction goals.
> (B) The recommendations do not increase emissions of criteria air pollutants and toxic air contaminants.
> (C) The recommendations ensure electrical system reliability.
> (D) The recommendations do not cause undue shifting of costs to bundled service customers of an electrical corporation or to direct transaction customers.[17]

The Commission interpreted the first phase required by SB 237 as a "mandate," and issued D.19-05-043, implementing the 4,000 gigawatt hour increase for Direct Access transactions.[18] With respect to the second phase, the Commission found that because it could not make the required statutory findings, it could not recommend to the Legislature to further reopen Direct Access.[19]

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16 *Id.*, §365.1(e).
17 *Id.,* §365.1(f).
18 *Decision Regarding Increased Limits for Direct Access Transactions,* D.19-05-043 (May 30, 2019).
19 Decision at 19.

As stated above, Applicants interpret SB 237 as mandating that the Commission recommend how further reopening of Direct Access <u>will</u> occur.[20] Applicants further contend that "the Commission assumed it had the discretion and right to overturn the will of the Legislature when it elected to ignore the statutory duties imposed on it by SB 237, based only on a questionable and highly discriminatory list of reasons why Direct Access should not be expanded."[21] However, the plain and commonsense language of SB 237 supports the Commission's determination.

The "rules" of statutory interpretation are well established – courts "begin by examining the statutory language, giving it a plain and commonsense meaning."[22] When interpreting a statute, "[t]he meaning of a statute may not be determined from a single word or sentence; the words must be construed <u>in context</u>, and the provisions relating to the same subject matter <u>must be harmonized to the extent possible</u>."[23] Here, Applicants only cite subsection (f)(1) as the full obligation of the Commission, while failing to cite the following subsection (f)(2) which requires that the Commission make <u>specific findings</u> in its development of any recommendations regarding Direct Access reopening. Applicants therefore fail to interpret subsection (f)(1) in the context of the full directives of the Legislature in SB 237.

Applicants' interpretation of SB 237 also fails when examined in light of the full statutory scheme of SB 237. "An interpretation that renders related provisions nugatory must be

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20 Application at 4 ("[d]espite [the] clear directive [of SB 237], the Decision does not provide recommendations on implementing a further direct access reopening schedule. Nor does the Decision include a proposed phase-in period").

21 Application at 4.

22 *Smith v. LoanMe, Inc.* (2021) 11 Cal.5th 183, 190 (quoting *Meza v. Portfolio Recovery Associates, LLC* (2019) 6 Cal.5th 844, 856-57); *see also New Cingular Wireless PCS, LLC v. Public Utilities Comm'n* (2016) 146 Cal.App.4th 784, 795.

23 *Save Lafayette Trees v. East Bay Regional Park District* (2021) 280 Cal.Rptr.3d 679, 700 (emphasis supplied) (quoting *Lungren v. Deukmejian* (1988) 45 Cal.3d 727, 735); *see also Smith,* 11 Cal.5th at 190.

avoided, each sentence must be read not in isolation but in the light of the statutory scheme, and if a statute is amenable to two alternative interpretations, the one that leads to the more reasonable result will be followed."[24] As set forth above, SB 237 *mandates* as phase 1 that the Commission reopen Direct Access by 4,000 gigawatt hours by January 1, 2019,[25] which the Commission directed in D.19-05-043. SB 237 then carves out phase 2, at issue here, which requires Commission analysis on implementing further reopening. The Legislature could have mandated a further reopening in phase 2 as it did in phase 1, but it did not. Instead, the Legislature requested the analysis of the Commission, provided in recommendations regarding reopening. With the full provisions of SB 237 read in context, the Commission's phase 2 recommendation against reopening was not only reasonable and within the Commission's discretion, but it was also in accordance with SB 237.

#### 2. Even if the Statutory Language in SB 237 Permits More Than One Reasonable Interpretation, the Legislative History Supports the Commission's Interpretation of SB 237

As noted above, statutory interpretation is based on "effectuat[ing] the law's purpose," and courts first look to the statutory language, giving it "plain and commonsense meaning."[26] If, however, "the statutory language permits more than one reasonable interpretation, courts may consider other aids, such as the statute's purpose, legislative history, and public policy."[27] While the plain meaning of SB 237 is clear, as set forth above, the legislative history provides further clarification as to the intent of the Legislature to require the Commission to make the necessary findings in connection with its recommendation on whether to reopen Direct Access.

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24 *Id.* at 701 (citations omitted).

25 Cal. Pub. Utils. Code §365.1(e).

26 *Smith,* 11 Cal.5th at 190 (quoting *Meza v. Portfolio Recovery Associates, LLC* (2019) 6 Cal.5th 844, 856-57).

27 *Id.*

The original bill, as introduced by Senator Hertzberg on February 6, 2017, and amended as of June 13, 2018, would have required the Commission to completely eliminate the cap on Direct Access over three years, commencing on July 1, 2019.[28] In a bill analysis from the Assembly Committee on Utilities and Energy, the statutory capping of enrollment in Direct Access as a result of the energy crisis was discussed, along with the past reopening and expansion of Direct Access in 2010 to 13 percent of retail electric load.[29] "Comments" on the analysis include reservations on the reopening of Direct Access:

- "Given the shaky status of [Resource Adequacy], is this the right time to contribute to the destabilization of the market by removing the cap on [Direct Access]?"[30]

- "The CPUC reports that it is seeing some of the same trends in the electricity marketplace that preceded the last energy crisis in California. Specifically, in a forward to what is called "The Green Book," released in May [2018], CPUC President Michael Picker made the following statement. "In light of this concern that procurement is already unstable in the state, should the Legislature compound the instability by removing the cap on [Direct Access] at this time?""[31]

In a bill analysis from the Assembly Committee on Appropriations regarding Senator Hertzberg's bill as written, the analysis cites the status of the electricity market at that time as having "undergone significant changes since the energy crisis," of which "[m]any of those changes continue."[32] The analysis further states that the Commission, while noting the "potential

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28 *See* Text of Senate Bill No. 237, Amended in Assembly June 13, 2018, available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB237; *see also* Assembly Committee on Utilities and Energy, June 26, 2018, at 1, available at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB237 (summarizing Senate Bill No. 237 as requiring the Commission "to eliminate the cap over three years, commencing on July 1, 2019, on the "direct access" (DA) program . . . .").

29 *See* Assembly Committee on Utilities and Energy, June 26, 2018, at 2, available at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB237.

30 *Id.* at 4.

31 *Id.*

32 *See* Assembly Committee on Appropriations, August 9, 2018, at 2, available at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB237.

for benefits to result from these changes" has also "expressed concerns" regarding the lack of a "coherent and comprehensive plan" to further deregulate the electric markets. The analysis recommends that "the author [of SB 237] may wish to consider a more limited expansion."[33]

As of August 21, 2018, the bill was amended to remove the requirement to completely eliminate the cap on DA. Instead, the amended bill required the Commission to provide recommendations to the Legislature regarding a second reopening of Direct Access.[34]

As of August 24, 2018, the bill was again amended to require two distinct actions by the Commission: (1) expand the DA program to 16 percent, or 4,000 gigawatt hours, apportioned across the service territories of the IOUs (with all DA customers already enrolled as of January 1, 2019 remaining eligible to participate in DA); and (2) report to the Legislature by June 1, 2020 on further expansion of the program, and with the recommendations "conditioned on specified findings."[35] As to the requirement that the Commission provide recommendations on reopening, the Comment portion in the August 24, 2018 Summary of the Senate Third Reading discusses the analysis being conducted at the Commission on customer choice and its effect on the "rapidly changing electricity market . . . to ensure continued reliable, clean, and affordable electricity for customers and equitable treatment for all market participants."[36] The Comment goes on to state that:

> [t]he recommendations on expansion of DA required by this bill are consistent with the CPUC's work on customer choice. The expansion of the DA program called for in this bill may be premature given the CPUC's warning that they observe [sic] similar

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33 *Id.*

34 Proposed amendment to California Public Utilities Code section 365.1(e), text of Senate Bill No. 237, as amended in Assembly, August 21, 2018, available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB237

35 Senate Third Reading, SB 237 (Hertzberg), as amended, at 1 (emphasis added), available at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB237

36 *Id.* at 3.

> circumstances in the electricity market as they observed before the energy crisis of 2001.[37]

On August 30, 2018, the Assembly passed the bill, and the Senate Committee on Energy, Utilities and Communications held a hearing to consider the bill. The Senate Committee analysis of the bill, which was ultimately passed in the Senate on August 31, 2018, summarizes the bill, discussing the requirement that the Commission reopen the DA program by 4,000 GWh, and the requirement that the Commission subsequently report to the Legislature regarding further reopening.[38] The analysis states that the bill" [r]equires that the [Commission] recommendations be <u>conditioned on</u> specified findings"[39] (that reopening would be consistent with GHG emission goals, would not increase criteria air pollutants and toxic air contaminants, would ensure electric system reliability, and would not cause undue cost shifting). The analysis includes a discussion of the complexities of reopening Direct Access, and notes that the Commission:

> [H]as stated that California must consider how to shape [the California energy market] in a way that continues to ensure reliable, clean, and affordable electricity for customers and equitable treatment for all market participants. The CPUC warns that the state does not currently have a plan to address these issues.

On the same day of this hearing, the bill was passed with no amendments.

Consistent with the Committee Analysis, the Legislative Counsel's Digest for SB 237 states that:

> This bill would require the commission to provide to the Legislature recommendations on the adoption and implementation of a 2nd direct transactions reopening schedule. <u>The bill would require the commission, in developing the recommendations, to make certain findings</u>.[40]

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37 *Id.*

38 Senate Committee on Energy, Utilities and Communications, 8/31/18 Hearing, Analysis of SB 237 (Version 8/24/28, As Amended), at 2, available at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB237

39 *Id.* (emphasis added).

40 SB 237, Legislative Counsel's Digest, paragraph 3.

As a whole, the legislative history of SB 237 contemplates a discussion of the most prudent course to reopen Direct Access in light of the history of California electricity deregulation and the potential concerns regarding the impacts of reopening Direct Access. Importantly, the legislative history specifically requires any recommendation regarding Direct Access to be conditioned on the Commission making all of the findings listed in section 365.1(f)(2).

Consistent with both the statutory language and the legislative history, the Commission carefully considered the required findings, and in determining that it could not make all of those findings, developed its recommendation against reopening Direct Access. In doing so, the Commission acted within the law, and did not abuse its discretion.

### C. The Decision is Adequately Supported by the Commission's Findings and Meets the Requirements of California Public Utilities Code Sections 365.2(f)(1) and 1757.1

Applicants contend that the Decision's findings "are flawed, without merit, and are highly discriminatory,"[41] and do not meet the "substantial evidence" standard required by California Public Utilities Code section 1757.[42] Contrary to Applicants' positions, however, the Decision is in fact adequately supported by the Commission's findings based on the entire administrative record.[43]

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41 Applicants cite section 1757, which is the standard of review for complaint, enforcement, ratemaking, or licensing proceedings, as the applicable statute. However, in this quasi-legislative proceeding, section 1757.1 provides the applicable standard of review. The only difference between sections 1757 and 1757.1 is that section 1757.1 does not include review of whether "the findings in the decision of the commission are . . . supported by substantial evidence in light of the whole record." Instead, section 1757.1 focuses on whether the Decision is adequately supported by the findings.

42 Application at 17.

43 *See City of Vernon v. Public Utilities Comm'n* (2001) 88 Cal.App.4$^{th}$ 672, 677 (review limited to a determination based on the "entire administrative record" of factors set forth in California Public Utilities Code section 1757.1).

As set forth above, Commission decisions are given great deference by courts, and there is a "strong presumption of validity of the commission's decisions."[44] Courts apply a "strong presumption of the correctness of the findings . . . of the commission, which may choose its own criteria or method or arriving at its decision.[45] In addition, when conflicting inferences can reasonably be drawn from the facts, the weighing of factors by the Commission is a matter within the exclusive jurisdiction of the Commission.[46] Even if the Section 1757 "substantial evidence" standard applied,[47] "[t]o accomplish the overturning of a Commission finding for lacking the support of substantial evidence, the challenging party must demonstrate that based on the evidence before the Commission, a reasonable person could not reach the same conclusion."[48]

Applicants contend that the Commission erred in its analysis regarding ESP past procurement performance, given the ESPs' 23-year track record of meeting their procurement obligations. Applicants also point out that all LSEs are subject to identical obligations for Resource Adequacy (RA), Renewable Portfolio Standard (RPS), Integrated Resource Planning (IRP) and GHG requirements.[49] In addition, Applicants argue that the Commission erred in finding that unpredictable load migration could destabilize the state's energy system.[50]

In making its determination for phase 2 of this proceeding, the Commission relied on a Draft Staff Report, 54 sets of Comments filed, and party participation at a Commission workshop. Based on the record, the Commission made findings in support of its Decision to

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44 *Greyhound,* 68 Cal.2d at 410-11.

45 *Pacific Gas and Electric Co.,* 237 Cal.App.4th at 838 (quoting *Pacific Tel. & Tel. Co. v. Public Utilities Comm'n* (1965) 62 Cal.2d 634, 647).

46 *Pacific Gas and Electric Co.,* 237 Cal.App.4th at 838-839 (citations omitted).

47 *See supra* n. 41.

48 *Pacific Gas and Electric Co.,* 237 Cal.App.4th at 839 (citations omitted).

49 Application at 16-19.

50 *Id.* at 19-20.

recommend against reopening of Direct Access, in accordance with California Public Utilities Code sections 365.1(f)(2) and 1757.1.

The Commission found that it could not make the first two out of the four required findings in California Public Utilities Code Section 365.1(f)(2), and therefore, concluded it could not recommend to the Legislature that Direct Access should be reopened. First, the Commission could not find that expansion of Direct Access will ensure system electric reliability, "given the concerns raised in the Staff Report and the urgent reliability challenges that the state faces."[51] In support of this finding, the Commission found that given the rotating outages that California experienced in Summer 2020 due to capacity and reliability challenges, near-, mid-, and long-term actions are needed to ensure summer reliability.[52] The Commission further found that while considerable new generation has been ordered by the Commission, construction of new generation requires financing, and financing is typically obtained by showing long-term load commitments.[53] Without long-term load certainty, LSEs cannot demonstrate the long-term customer commitment to support or enter into the long-term power purchase agreements necessary to finance construction of new generation.[54] The Commission also found that Direct Access customers generally enter into short term agreements with ESPs, and that ESPs primarily fill their obligations through short-term contracts, or unspecified power purchased on the CAISO energy market.[55] The Commission further found that expanding Direct Access will allow load migration between LSEs, causing fragmentation of the electricity market, which will result in

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51 Decision at 19.
52 *Id.* at 27, Findings of Fact 1-2.
53 *Id.,* Findings of Fact 3-4.
54 *Id.,* Finding of Fact 5.
55 *Id.* at 28, Finding of Fact 6.

CCAs and ESPs having difficulty financing new generation needed for system reliability and for GHG emissions reduction goals).[56]

Second, the Commission could not find that reopening Direct Access would be consistent with the state's GHG emission reduction goals. The Commission found that ESPs' power purchases consist largely of unspecified power, which the California Air Resources Board has determined has higher GHG emissions and particulate pollutants than the power mix used by IOUs and CCAs.[57] The findings included that as of 2019 the power mix for each type of LSE is: IOUs – 64.4 percent GHG-free; CCAs – 79.1 percent GHG-free; and ESPs – 30.6 percent GHG-free.[58] Furthermore, the Commission found that if ESPs continue to rely on unspecified power, load migration due to Direct Access expansion will result in increased GHG emissions.[59]

Given the Commission's extensive support of its Decision, Applicants' contentions regarding the Decision being unsupported by findings or lacking the support of substantial evidence must be dismissed. While Applicants' may not agree with the Commission's Decision, the Decision is adequately supported by the findings as required by California Public Utilities Code section 1757.1.

### D. The Decision Does Not Violate the Dormant Commerce Clause Because It Treats In-State and Out-of-State Businesses Equally

Other than a general description of the dormant Commerce Clause, a statement that "a nondiscriminatory alternative does exist" without any further explanation, and a general statement that "[t]he practical effect of the Decision is to favor California-based IOUs and CCAs, to the detriment of the state's ESPs, the overwhelming majority of which are out-of-state

56 *Id.*, Finding of Fact 7-8.
57 *Id.,* Finding of Fact 9.
58 *Id.,* Finding of Fact 10.
59 *Id.,* Finding of Fact 12.

corporations," Applicants fail to articulate exactly how the Decision violates the dormant Commerce Clause. This inability to demonstrate any discriminatory treatment is likely because the Decision equally affects both in-state ESPs (such as Applicant Alliance for Retail Energy Markets' (AReMs') member Calpine Energy Solutions, headquartered in San Diego, California, and Pilot Power Group, also headquartered in San Diego, California) as well as out-of-state ESPs (such as AReMs' member Constellation New Energy, headquartered in Baltimore, Maryland).

Article I, Section 8, Clause 3 of the United States Constitution (the Commerce Clause), provides Congress with the power "to regulate commerce . . . among the several states, . . . ."[60] From this authorization of Congressional power, courts have inferred a restriction on state power known as the "dormant Commerce Clause," which limits the States' authority to enact or enforce laws that discriminate against or unduly burden interstate commerce.[61] Courts will strike down a state law if it expressly mandates differential treatment of in-state and out-of-state competing economic interests in a way that benefits the former and burdens the latter.[62] A law that is not facially discriminatory can still be struck down if the effect or purpose of the law is to burden interstate commerce.[63]

The Court has specifically held that state laws, such as the Decision at issue here, that treat in-state and out-of-state businesses equally cannot violate the dormant Commerce Clause. In *Minnesota v. Clover Leaf Creamery Co.,*[64] the Supreme Court upheld a state law banning the

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60 U.S. Constitution, Art. 1, §8, Clause 3.

61 *See Granholm v. Heald,* 544 U.S. 460, 492-93 (2005) (state law allowing in-state wineries, but not out-of-state wineries, to ship their products to consumers violated dormant Commerce Clause by discriminating against out-of-state wineries).

62 *Id.*

63 *Pike v. Bruce Church, Inc.,* 397 U.S. 137, 142-43 (1970) (citing *Huron Portland Cement Co. v. City of Detroit,* 362 U.S. 440-443 (1960) (applying a balancing test that evaluates whether the burdens on interstate commerce are "clearly excessive in relation to the putative local benefits").

64 *Minnesota v. Clover Leaf Creamery Co.*, *et al.,* 449 U.S. 456, 470-74 (1981).

retail sale of milk products in plastic, nonreturnable containers but permitted sales in other nonreturnable, nonrefillable containers, such as paper cartons. The Court found no discrimination against interstate commerce, because both in-state and out-of-state interests could not use the plastic containers and therefore they were treated in the same manner.[65] Similarly, in *North American Meat Institute v. Becerra,*[66] the Federal District Court upheld a California law that banned selling veal or pork in the state where the animal was confined in a "cruel manner," rejecting the argument of out-of-state meat sellers that the law discriminated against interstate commerce in violation of the dormant Commerce Clause by effectively excluding them from California's market. The court found that the law applied equally to California meat producers and out-of-state meat producers and thus was not discriminatory in effect, stating that an "equal opportunity" burden on all targeted goods is not invalid under the dormant Commerce Clause.[67]

Applicants' argument here, that the dormant Commerce Clause is violated because some out-of-state businesses will be impacted, is identical to the arguments that have been previously rejected by the Supreme Court and other courts. The Commission's recommendation to not reopen Direct Access applies equally to both in-state and out-of-state companies, and therefore the dormant Commerce Clause argument does not apply.

Moreover, courts considering regulations imposing an only "incidental" burden on interstate commerce have upheld those regulations. In explaining these decisions, courts cite the state's power to make laws governing matters of local concern even if a law in some measure

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65 *Id.; see also Exxon Corp. v. Governor of Maryland,* 437 U.S. 117, at 125-26 (1978) (finding no violation of the dormant Commerce Clause by a Maryland statute that prohibited producers or refiners of petroleum products from operating retail service stations in the state, because the fact that the burden incidentally fell on out-of-state companies (no in-state producers or refiners actually existed) "does not lead . . . to a conclusion that the state is discriminating against interstate commerce" as the statute does not "distinguish between in-state and out-of-state companies in the retail market.").

66 *North American Meat Institute v. Becerra,* 420 F.Supp.3d 1014, 1025-27 (C.D. Cal. 2019).

67 *Id.*

affects interstate commerce or even, to some extent, regulates it.[68] The Supreme Court has long recognized public health, the environment, and natural resources as legitimate matters of local concern, and state laws intended to protect them justify the burden on interstate commerce so long as the law is not motivated by an economic protectionist purpose.[69] Therefore, even if the dormant Commerce Clause somehow applied in this situation, the Commission's findings regarding reliability of the electric system and the environmental concerns that support its decision to recommend against reopening Direct Access would likely justify any burden on interstate commerce.

### E. The Decision Does Not Violate Applicants' Equal Protection Rights

Applicants broadly argue that the Decision unlawfully discriminates against both non-residential customers and the ESPs that wish to serve them and therefore violates their right to equal protection under the Fourteenth Amendment of the United States Constitution, and the California State Constitution.[70] Applicants state that the Decision "constitutes a state-imposed barrier to two groups," and cite the "disparate treatment" of ESPs as compared to CCAs and IOUs which are able to serve all non-residential customers within their service areas.

However, Applicants provide no legal support for this argument other than a cite to a Supreme Court case from 1880 generally stating that a state's legislative or administrative action can violate the equal protection of the laws, and a 1993 case discussing standing to bring an equal protection claim. Any analysis of a state law and whether it implicates equal protection rights must apply the "rational basis" test and whether the law is rationally related to any

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68 *Hunt v. Wash. State Apple Advert. Comm'n,* 432 U.S. 333, 349-50 (1977) (citations omitted).

69 *See Maine v. Taylor,* 477 U.S. 131, 151-52 (1986) ("As long as a State does not needlessly obstruct interstate trade or attempt to place itself in a position of economic isolation [citation omitted], it retains broad regulatory authority to protect the health and safety of its citizens and the integrity of its natural resources.").

70 Application at 21.

legitimate government purpose.[71] On "rational-basis review," a classification in a statute or regulation bears a "strong presumption of validity."[72] In this case, as set forth above regarding the Commission's findings supporting its recommendation against reopening Direct Access, significant public policy justifications exist which implicate electric system reliability and the environment. Therefore, under the "rational basis test," Applicants' equal protection argument should be rejected.

## III. CONCLUSION

For the foregoing reasons, the Commission should deny the Application for Rehearing.

Respectfully submitted,

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August 13, 2021

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[71] *See Federal Communications Comm'n v. Beach Communications, Inc., et al.,* 508 U.S. 307, 313 (1993) ("[i]n areas of social and economic policy, a statutory classification that neither proceeds along suspect lines nor infringes fundamental constitutional rights must be upheld against equal protection challenge if there is any reasonably conceivable state of facts that could provide a rational basis for the classification"); *see also Minnesota,* 449 U.S. at 461-62 (considering whether a state classification between milk containers is "rationally related" to the legitimate state purpose of promoting resource conservation, easing solid waste disposal problems, and conserving energy).

[72] *Id.* at 314.

# Submit comment on Second revised straw proposal

Initiative: Day-ahead market enhancements

**1. Please provide a summary of your organization's comments on the Day-Ahead Market Enhancements (DAME) second revised straw proposal:**

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the DAME second revised straw proposal. CalCCA supports this initiative's objective of improving the day-ahead market's ability to sufficiently schedule resources to cover net-load uncertainty and reduce the need for out-of-market actions. However, the must-offer obligation elements proposed in the transition period create significant concerns that the proposal will increase costs to ratepayers while limiting the California Independent System Operator's (CAISO's) access to resources already procured to meet real-time energy needs.

CalCCA offers the following comments on the second revised straw proposal:

- CalCCA supports applying market power mitigation to imbalance reserve offers in the IFM and reliability capacity offers in the RUC;
- The CAISO should consider basing the default capacity bid on opportunity costs rather than historical spinning reserve prices;
- CalCCA supports a mechanism to consider energy offer costs when awarding imbalance reserves and reliability capacity in the upward direction, but the proposed approach may not meet the objective of awarding imbalance reserves and reliability capacity to low energy cost resources; and
- The CAISO should (1) maintain the real-time must offer obligation for resource adequacy (RA) resources, and (2) require RA resources bid zero dollars for imbalance reserves and reliability capacity and evaluate the impacts of removing the zero-dollar bidding requirement within the Extended Day-Ahead Market (EDAM) initiative.

**2. Please provide your organization's comments on the proposed changes to the market power mitigation (MPM) pass for the integrated forward market (IFM):**

CalCCA supports applying market power mitigation to imbalance reserve offers in IFM and reliability capacity offers in RUC. However, as discussed in section 8, it is not clear historical spinning reserve prices will reflect costs of being available as imbalance reserves or reliability capacity.

**3. Please provide your organization's comments on the proposed changes to the IFM:**

No comments at this time.

**4. Please provide your organization's comments on the proposal for an additional market pass to perform MPM for the residual unit commitment (RUC) process:**

CalCCA supports applying market power mitigation to imbalance reserve offers in IFM and reliability capacity offers in RUC. However, as discussed in section 8, it is not clear historical spinning reserve prices will reflect costs of being available as imbalance reserves or reliability capacity.

**5. Please provide your organization's comments on the proposed RUC process changes:**

No comments at this time.

**6. Please provide your organization's comments on the proposed real-time market ramp deviation settlement:**

No comments at this time.

**7. Please provide your organization's comments on the proposed method to account for energy offer cost in upward capacity procurement:**

CalCCA supports a mechanism to consider energy offer costs when awarding imbalance reserves and reliability capacity in the upward direction, but the proposed approach may not meet the objective of awarding imbalance reserves and reliability capacity to low energy cost resources. As a way to account for energy offer costs when procuring upward imbalance reserves or reliability capacity, the CAISO proposes to make resources ineligible to be awarded imbalance reserves or reliability capacity on any capacity segment with an associated energy bid that exceeds the forecasted price under P97.5 uncertainty. However, in real-time, a resource's energy bid would not be capped at the forecasted price. This leaves the opportunity for resources to bid below the cap in day-ahead such that they are awarded imbalance reserves or reliability capacity in day-ahead and then bid for energy above the cap in real-time. This limits the ability of the CAISO's proposal to meet the objective of awarding imbalance reserves and reliability capacity to lower energy cost resources. CAISO should consider capping real-time energy bids at the higher of forecasted P97.5 price or the resources default energy bid price to address concerns that real-time energy bid caps will dispatch resources below their marginal costs.

**8. Please provide your organization's comments on the proposed default capacity bid, including feedback on the appropriate price based on historical spinning reserve prices:**

CalCCA supports developing market power mitigation measures for imbalance reserves and reliability capacity, but additional discussion is needed on how to establish the default capacity bid for those products. The CAISO proposes to use historical spinning reserve prices to inform the default capacity bid price, which would set the mitigated bid price for all resources except those with a negotiated price. However, it is not clear historical spinning reserve prices will appropriately reflect competitive prices for imbalance reserves and reliability capacity given imbalance reserves and reliability capacity will provide different services than spinning reserves and they will be used for different purposes. For capacity products, the default capacity bid should represent a resource's opportunity cost for providing the product. Rather than basing the default capacity bid on historical spinning reserve prices, the default capacity bid should reflect opportunity costs.

In addition, the CAISO should clarify whether it is the CAISO's intent to utilize the default capacity bid to insert bids for imbalance reserves and reliability capacity in day-ahead market. Currently, the CAISO inserts bids for RA resources at their default energy bid in both day-ahead and real-time in the event scheduling coordinators do not submit energy bids themselves. It is not yet clear how bid insertion will work in relation to the new products proposed in DAME. The CAISO should clarify if they will insert imbalance reserve and reliability capacity bids into day-ahead at the default capacity price. The CAISO should also clarify if resources with imbalance reserve or reliability capacity awards will have bids inserted for energy at their default energy bid if they do not bid themselves in real-time, as is done for RA resources today.

**9. Please provide your organization's comments on the proposed variable energy resources eligibility to provide new products:**

No comments at this time.

**10. Please provide your organization's comments on the proposed transition period for DAME enhancements:**

CalCCA urges the CAISO to reconsider the modifications to the RA must offer obligations proposed in this initiative. Today, RA resources are obligated to submit RUC availability bids at zero dollars and are not paid the RUC clearing price if committed through the RUC process. RA resources must then bid into real-time, regardless of whether or not they are committed in day-ahead. This structure is in place because load-serving entities (LSEs) have already entered into contracts with RA resources paying for them to be available through real-time to provide energy. Under this initiative, the CAISO proposes a transition period that would last until the year of EDAM onboarding, in which RA resources would be required to bid zero for imbalance reserves and reliability capacity in the day-ahead market and would receive the marginal price for both products. RA resources would then be required to bid into the real-time market regardless of their imbalance reserve or reliability capacity awards. After the transition period, RA resources would no longer be required to bid zero for imbalance reserves or reliability capacity and would not be obligated to bid in real-time if they did not receive a day-ahead award. As described below, CalCCA recommends the CAISO maintain the real-time must offer obligation for RA resources and require RA resources bid zero dollars and not receive the marginal price for imbalance reserves and reliability capacity until the impacts of removing the zero-dollar bidding requirement can be evaluated within the EDAM initiative.

First, the CAISO should maintain the real-time RA must offer obligation given the cost and reliability impacts of removing it. LSEs in California have entered into RA contracts that procure capacity obligated to be available to the CAISO market to be turned into energy. Because RA resources are already paid to be available to provide energy through real-time, the CAISO should not release that capacity already paid for after the day-ahead market. The CAISO proposes the transition period in part to allow time for RA contracts to be updated to account for the removal of the zero-dollar bidding requirement. However, the ability for LSEs to renegotiate RA contracts already executed to account for this change will be difficult given tight supply conditions in the RA market. The CAISO's Stack Analysis shows that total RA capacity is very limited, with little or no excess of system resources over coming years until additional resources come online through the Integrated Resource Planning process.[1] Such tightness in the RA market will make it difficult for LSEs to renegotiate RA contracts to reflect the new structure in which costs of real-time availability are recovered through the new DAME products rather than RA contracts. The result of implementing this change under current RA market conditions could result in LSEs paying for resources to be available to provide energy twice; first within the RA market when procuring RA capacity and second within the day-ahead market when procuring imbalance reserves and reliability capacity. As such, CalCCA has significant concerns around the feasibility of renegotiating RA contracts at a reasonable price to facilitate this structural change without significant increases in ratepayer costs.

Additionally, if RA resources are relieved of their must offer obligation after the day-ahead, the CAISO market would not receive the full benefit of having all resources and their attributes that have already been paid for available to meet grid needs. Relieving RA resources of their real-time must offer obligation after day ahead could result in the CAISO needing to rely on out-of-market actions to access the resource in the event conditions in real-time require additional resources beyond what is procured through the imbalance reserve or reliability capacity products to maintain grid reliability. Given the costs of making resources available through real-time are already covered in RA contracts, the CAISO should not limit its access to resources already procured to maintain grid reliability, and instead, should maintain the real-time must offer obligation for RA resources within this initiative.

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[1] *Testimony of Jeff Billinton On Behalf of the California Independent System Operator*, Rulemaking (R.) 20-11-003, Jan. 11, 2021, Table 2 at 12.

CalCCA understands the rationale behind removing the zero-dollar bidding requirement under an EDAM where resources in other balancing authority areas would be bidding for the same products without the zero-dollar bidding requirement. However, given the difficulty LSEs will face renegotiating contracts under current RA market conditions, the CAISO should not consider removing the zero-dollar bidding requirement within the DAME initiative. Additionally, the CAISO should not pay RA resources the marginal price for imbalance reserves and reliability capacity since existing RA contracts already compensate resources for being available through real-time. Instead, the CAISO should maintain the zero-dollar bidding requirements and continue not to pay resources for capacity already accounted for in RA contracts indefinitely until this change can be evaluated within the EDAM initiative. This consideration should include potential alternatives to modifying the zero-dollar bid requirement given the double payment concerns and tight RA market conditions that exist today.

**11. Please provide your organization's comments on the proposed treatment of metered subsystems, existing transmission contracts, and transmission owner rights:**

No comments at this time.

**12. Please provide your organization's comments on the proposed EIM Governing Body advisory role classification:**

No comments at this time.

**13. Please provide any additional comments on the DAME second revised straw proposal that have not previously been addressed:**

CalCCA is interested in how this proposal interacts with storage, co-located, and hybrid resources. Specifically, CalCCA asks how the individual components of co-located resources would be priced and dispatched under the current proposal for default capacity bids, and if and how the day-ahead market will award imbalance reserves and reliability capacity to co-located resources in accordance with their aggregate capability constraints.

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

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| Order Instituting Rulemaking to Revise General Order 156 to Include Certain Electric Service Providers and Community Choice Aggregators and Encourage Voluntary Participation by Other Non-Utility Entities Pursuant to Senate Bill 255; Consider LGBT Business Enterprise Voluntary Target Procurement Percentage Goals; Incorporate Disabled Business Enterprises; Modify the Required Reports and Audits; and Update Other Related Matters. | R.21-03-010 |

# CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON STAFF PROPOSAL, WORKSHOP, AND ADDITIONAL QUESTIONS


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August 18, 2021

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## SUMMARY OF RECOMMENDATIONS

- ✓ The CCAs commit, to the extent possible and in compliance with the law, to continue to collaborate with one another, as well as Commission staff, to contribute to the success of the Supplier Diversity Program.

- ✓ CalCCA Supports the Opening Comments filed by California Choice Energy Authority.

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

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| Order Instituting Rulemaking to Revise General Order 156 to Include Certain Electric Service Providers and Community Choice Aggregators and Encourage Voluntary Participation by Other Non-Utility Entities Pursuant to Senate Bill 255; Consider LGBT Business Enterprise Voluntary Target Procurement Percentage Goals; Incorporate Disabled Business Enterprises; Modify the Required Reports and Audits; and Update Other Related Matters. | R.21-03-010 |

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON STAFF PROPOSAL, WORKSHOP,
AND ADDITIONAL QUESTIONS**

The California Community Choice Association[1] (CalCCA) submits these Reply Comments in response to the *Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo)*, issued on June 25, 2021, the *Email Ruling Issuing Staff Proposal and Entering the Staff Proposal Into the Record* (Email Ruling), issued on July 16, 2021, *Staff Proposal to Revise General Order 156 for the Supplier Diversity Program* (Staff Proposal), issued on July 16, 2021, and the Workshop *on General Order 156 (Supplier Diversity Program)* (Workshop), held on July 21, 2021.

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

## I. INTRODUCTION

CalCCA appreciates the opportunity to provide these Reply Comments. As reflected in CalCCA's opening comments on the Staff Proposal, Workshop, and Questions,[2] and in the individual meetings held on the Supplier Diversity Program (Program) with Commission staff by each Community Choice Aggregator (CCA), CalCCA's members are committed to working with the Commission and Commission staff to develop and implement the program, and to contribute to its success.

CalCCA's Opening Comments addressed the following: (1) the proposed revisions to GO 156 consistent with the limited requirements of Senate Bill (SB) 255 and the restrictions on CCAs with respect to procurement, including Proposition 209; (2) the recommendations for the expansion of diverse suppliers in the GO 156 Clearinghouse; and (3) a request to reject the recommendations in the Staff Proposal regarding expansion of the workforce and board diversity reporting requirements by CCAs.

CalCCA does not change its position on any of the topics that it raised in Opening Comments, but rather uses this opportunity to address the following additional issues:

- ✓ The CCAs commit, to the extent possible and in compliance with the law, to continue to collaborate with one another, as well as Commission staff, to contribute to the success of the Program.

- ✓ CalCCA Supports the Opening Comments filed by California Choice Energy Authority (CCEA).[3]

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2 *California Community Choice Association's Comments on Staff Proposal, Workshop, and Additional Questions,* August 4, 2021 (Opening Comments).

3 *Opening Comments of the California Choice Energy Authority on the Staff Proposal,* August 4, 2021 (CCEA Opening Comments).

## II. CCAS WILL CONTINUE TO COLLABORATE WITH ONE ANOTHER AND WITH COMMISSION STAFF TO THE EXTENT POSSIBLE AND IN COMPLIANCE WITH THE LAW TO SHARE BEST PRACTICES AND ENCOURAGE SUPPLIER DIVERSITY

The CCAs have and will continue to work individually and through CalCCA to collaborate with Commission staff, and with one another (to the extent possible and in compliance with law), as to methods and best practices to support the important goals of the Program. As set forth in the CCA reports and plans, each CCA has and will continue to utilize the resources provided by the Commission, as well as their own committed resources, to encourage procurement of categories of suppliers in the Program in accordance with all applicable laws, and governing ordinances and policies. The CCAs welcome Commission staff support and commit to supporting the Program.

## III. CALCCA SUPPORTS THE OPENING COMMENTS FILED BY CALIFORNIA CHOICE ENERGY AUTHORITY

CalCCA supports CCEA's Opening Comments. The business model of CCEA, as a Joint Powers Authority providing regulatory and support services to small cities operating CCAs, is one example of the varying size and composition of CalCCA's members.

## IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

August 18, 2021

| DOCKETED | |
|---|---|
| **Docket Number:** | 21-SIT-01 |
| **Project Title:** | 21-SIT-01, SB100 Implementation Planning for SB100 Resource Build |
| **TN #:** | 239403 |
| **Document Title:** | CalCCA Comments on SB 100 Resource Mapping WS 08 20 21 |
| **Description:** | N/A |
| **Filer:** | Chester Hong |
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| **Docketed Date:** | 8/20/2021 |

**COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE CALIFORNIA ENERGY COMMISSION ON THE JOINT AGENCY WORKSHOP ON NEXT STEPS TO PLAN FOR SENATE BILL 100 RESOURCE BUILD: RESOURCE MAPPING**
**August 12, 2021**

**Docket Number 21-SIT-01**
**SB 100 Implementation: Planning for SB 100 Resource Build**

The California Community Choice Association[1] (CalCCA) submits these comments to the California Energy Commission (Commission) in Docket Number 21-SIT-01 on the *Joint Agency Workshop on Next Steps to Plan for Senate Bill 100 Resource Build: Resource Mapping*, held on August 12, 2021.

## I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the Joint Agency Workshop on Next Steps to Plan for Senate Bill 100 Resource Build: Resource Mapping. Forward planning and coordination between the California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and the Commission (Joint Agencies) will play a critical role in ensuring California can meet its ambitious climate goals reliably and cost effectively. Understanding potential resource footprints will help ensure new resource build is sited appropriately and that transmission is available or built far enough in advance to accommodate the influx of clean resources that will come online to meet Senate Bill (SB) 100 targets.

## II. COMMENTS

CalCCA supports the Commission's development of potential renewable energy development footprints and consideration of key environmental and land use impacts in SB 100 implementation work. Because renewable resource build and new supporting infrastructure will

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

likely require large geographic footprints, upfront land-use planning will provide crucial information used to identify viable sites for development of resource and transmission build. Land use, environmental, and habitat concerns can create serious delays or project cancellations if not incorporated into site evaluation upfront. By incorporating these considerations into the SB 100 implementation process, the Joint Agencies can help steer resource and transmission build to less sensitive areas and avoid potentially serious delays or cancellations of projects needed to integrate future resource procurement.

The collaboration taking place early and often between the Joint Agencies in the SB 100, Integrated Resource Planning (IRP), and Transmission Planning processes will aid in ensuring resource procurement and new transmission build aligns. CalCCA supports utilizing resource maps developed in this analysis to inform the CAISO's 20-year Transmission Outlook. Given the time it takes to build generation and transmission, the Joint Agencies should consider how potential projects identified in the 10-year plan will also meet the needs identified in the 20-year Transmission Outlook and support projects that can be built at optimal sites identified in the Commission's land use mapping. This will ensure projects approved in the 10-year process support both short-term needs and long-term policy-driven needs.

## III. CONCLUSION

CalCCA appreciates Commission staff's efforts in building a resource map that considers environmental and land use data to examine SB 100 scenarios.

Dated: August 20, 2021

(*Original signed by*)

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

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| Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues. | ) ) ) ) ) | Rulemaking 20-05-012 (Filed May 28, 2020) |

**COMMENTS OF MARIN CLEAN ENERGY ON HEAT PUMP WATER HEATER CONTRACTOR TRAINING AND WORKFORCE ISSUES AND METHODS TO INCREASE SELF-GENERATION INCENTIVE PROGRAM TECHNOLOGIES' CONTRIBUTIONS TO SUMMER RELIABLITY**


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August 23, 2021

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

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| Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues. | Rulemaking 20-05-012 (Filed May 28, 2020) |

# COMMENTS OF MARIN CLEAN ENERGY ON HEAT PUMP WATER HEATER CONTRACTOR TRAINING AND WORKFORCE ISSUES AND METHODS TO INCREASE SELF-GENERATION INCENTIVE PROGRAM TECHNOLOGIES' CONTRIBUTIONS TO SUMMER RELIABLITY

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and Assigned Commissioner Rechtschaffen's August 3, 2021 *Assigned Commissioner's Ruling Requesting Comment on Heat Pump Water Heater Contractor Training and Workforce Issues and Methods to Increase Self-Generation Incentive Program Technologies' Contributions to Summer Reliability*, ("Ruling"), Marin Clean Energy ("MCE") hereby submits the following opening comments. In these comments, MCE responds to the Ruling's questions on the possible contribution from Self-Generation Incentive Program ("SGIP") technologies to summer reliability.

## I. COMMENTS

### A. Contribution from SGIP Technologies to Summer Reliability

Question 1:

> *Could higher SGIP incentives for certain SGIP budget and/or customer categories help contribute to grid reliability by summer 2022, by reducing peak loads? Which SGIP budget and/or customer categories have the greatest potential to contribute?*

Response to Question 1:

Higher, or "enhanced" SGIP incentives for certain SGIP budget and customer categories can help to contribute to grid reliability by summer 2022. Encouraging the large-scale expansion of deployed, customer-sided energy storage resources provide one of the best opportunities to reduce peak loads by summer 2022. Specifically, these technologies allow customers to charge during the mid-day period, when ample solar generation is available, and use this energy during the afternoon and evening peak demand periods. MCE believes that all SGIP budget categories that provide funding for customer-sided energy storage resources have the potential to make this contribution, including: the Large-Scale Storage, Small Residential Storage, Residential Storage Equity, Non-Residential Storage Equity, and Equity Resiliency budgets.

However, for these budget categories to reap benefits from additional incentives by summer 2022, three barriers must be overcome. First, Program Administrators ("PA") must quickly process and approve both currently pending applications and applications for any new incentives to ensure that all resources are fully deployed before summer 2022. Second, the Commission, PAs, Vendors, and all interested parties must work together to address the current energy storage supply chain issues resulting from the global pandemic (and the resulting backlog of existing installations). Third, increased demand for energy storage, largely in reaction to wildfires, climate change, and de-energizations and supply chain issues have resulted in higher labor and material costs for energy storage. Any additional incentives should take into account these higher costs, which could linger well into 2022 and beyond.

Question 2:

> *If higher SGIP incentives are offered to help contribute to grid reliability by summer 2022, should customers receiving the incentive be required to participate in a demand response aggregation program, or other demand response program? If so, which existing or proposed demand response programs should they be required to participate in? How long should participation be required? If higher incentives are offered, what amount do you recommend?*

Response to Question 2:

Customers who receive "enhanced" SGIP incentives to support grid reliability should be required to participate in a demand response ("DR") program that reduces peak load. Using higher incentives to increase DR program participation will help to ensure that the energy storage resources funded by enhanced SGIP incentives are used in a manner that maximizes grid reliability.

However, MCE urges the Commission to be flexible about the specific DR program that a customer must enroll in. In particular, customers of Community Choice Aggregators ("CCA") must be allowed to meet this requirement by participating in any of their CCA's DR programs, as long as the CCA DR program in question contributes to peak load reduction during the state's peak period of 4pm to 9pm. Further, if a CCA offers one or more relevant DR programs, these program(s) should be treated as the customer's "default" option(s), with participation in any IOU program limited to customers who opt out of the CCA's DR program.

It is essential that CCA customers are not defaulted into participation into an investor-owned utility ("IOU") DR program, as under DR program dual-participation rules found in the IOU tariffs, any resource that enrolls in an IOU DR program cannot enroll in any other DR program, including CCA DR programs.[1] This prohibition applies even if the two DR programs are not "competing" programs. Defaulting CCA customers into IOU DR programs would hence be

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1 *See*, PG&E Electric Rule 24, SCE Electric Rule 24, SDG&E Electric Rule 32.

anti-competitive, allowing the IOUs to use eligibility for SGIP incentives to block customer participation in CCA DR programs. Further, as required by the CCA Code of Conduct, IOUs should not be allowed to market against customer participation in competing CCA DR programs or use SGIP or DR funds to encourage CCA customers to opt out of CCA DR programs.

MCE has DR programs that would be ideal for many customers that would receive enhanced SGIP funding for grid reliability. For example, MCE's *Energy Storage Program*[2] offers performance-based compensation to participating customers in exchange for allowing MCE to directly monitor and control their energy storage systems ("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, both residential and non-residential, are aggregated into a virtual power plant ("VPP") and can also be manually dispatched in response to a California Independent System Operator ("CAISO") signal for emergency load reduction. At this point in time, the program is designed as a "load modifying resource" program, i.e., the participating resources are not participating directly in the CAISO market.

MCE also launched its *Peak Demand FLEXmarket*[3] program for the summer of 2021 that pays aggregators for shifting loads out of the peak period at the avoided cost of peak capacity (currently \$150/MWh), including higher payments (between \$200 - \$800/MWh) for up to 60 hours of load-shifting during event days when the grid is extremely constrained. The program does not prescribe the type of load reduction, allowing the market to respond with a variety of resource types, including electric vehicle charging, energy storage, smart thermostats/appliances, or

[2] Read more at https://www.mcecleanenergy.org/resiliency/
[3] Read more at https://www.mcecleanenergy.org/news/press-releases/mce-launches-new-grid-responsive-demand-flexmarket/

traditional demand response. Customers participating or enrolling in CCA programs such as these should not be forced to enroll in an IOU DR program or be precluded in any way from participating in a LSE-offered load reduction program.

Regarding the enhanced incentive levels for SGIP grid reliability resources, MCE recommends that the Commission adopt two distinct approaches for residential and non-residential customers, respectively. For residential customers, SGIP incentives are currently provided as a one-time, up-front rebate for residential storage systems based on the storage capacity being installed. The current incentive levels in Pacfic Gas & Electric's ("PG&E") service territory are as follows:

- Small Residential Storage - $0.20/Wh
- Residential Storage Equity - $0.85/Wh
- Equity Resiliency - $1/Wh

MCE supports continuing this approach for the enhanced incentives. The incentive for Residential Storage Equity and Equity Resiliency should be adjusted so that the incentives offered are at or near 100% current market price for an installed home energy storage storage system. The incentive for Small Residential Storage should likewise receive a meaningful upward adjustment to further incentivize residential customers in the general market to install energy storage systems.

For non-residential customers, MCE recommends that enhanced intentives include two elements. First, the enhanced incentives should increase the current up-front incentives for Large-Scale Storage, Non-Residential Storage Equity, and non-residential customers participating in the Equity Resliliency budget. Second, these customers should be offered a performance-based incentive payment based on the metered output from the ESS during peak periods. The specific amount of this performance-based SGIP incentive should be calculated based on the avoided cost of capacity needed to meet peak load.

As mentioned above, both residential and non-residential customers receiving enhanced SGIP benefits would be required to enroll in a peak load reducing DR program. Depending on the type of DR program, the customer may also receive additional payment for reducing load during peak hours from the respective DR program. However, payments for load reduction under the various DR programs vary greatly and can be minimal or non-existent for residential DR programs. Hence, MCE recommends that the enhanced SGIP incentive is set high enough to encourage customer participation under DR programs without relying on the incentives provided under the respective DR program.

Finally, MCE would like to point out that it is critical that energy storage customers who receive enhanced SGIP incentives for grid reliability should be required to enroll in DR programs that are "resiliency compatible." Resiliency Compatible DR programs would be defined as those programs that certify in writing that they will take reasonable steps to ensure that resiliency customer's batteries are fully charged prior to the commencement of any PSPS outage event, planned outage, or other high outage-risk conditions.

<u>Question 3.1</u>:

> *Should the Commission require new SGIP storage systems receiving any higher reliability incentive to enroll in a market-integrated residential or non-residential demand response program, the recently adopted out-of-market Emergency Load Reduction Program (ELRP), or a dynamic rate option (such as Critical Peak Pricing (CPP), or Real Time Pricing (RTP)? Should such a requirement be tied to higher incentives? If so, what amount?*

<u>Response to Question 3.1</u>:

For all enhanced SGIP storage budget categories, the Commission should require participation in a peak load reduction DR program. However, the Commission should *not* be prescriptive as to the type of program beyond requiring it to reduce peak loads. As previously noted, MCE's Energy Storage Program provides peak load reduction via direct control using

MCE's DERMS platform. Therefore, requiring participation in any type of IOU DR program or rate will severely impact MCE's program in a negative way due to the dual participation limitations described above.

See above suggestion for a method of calculating an appropriate incentive level.

Question 3.2:

> *Should new residential SGIP energy storage participants with solar receiving any higher reliability incentive be required to select a Virtual Power Plant aggregator and participate in the ELRP? Are there any downsides to the Commission requiring default enrollment into ELRP for new SGIP energy storage participants receiving a higher reliability incentive?*

Response to Question 3.2:

MCE agrees with the notion that existing solar customers who add storage offer the greatest potential value for peak load reduction and that they should be either required to select a Virtual Power Plant aggregator or directly participate in a DR program. However, MCE strongly opposes requiring customers to participate in the existing Emergency Load Reduction Program ("ELRP") but instead supports requiring customers to participate in a DR program offered by any load-serving entity ("LSE") or CCA that targets peak load reduction (if available). MCE strongly urges the Commission to avoid being overly prescriptive regarding which DR program customers must enroll under as this would be detrimental to non-IOU DR/load reduction programs such as MCE's Energy Storage Program and Peak Demand FLEXmarket Program, which could be as effective, or *more effective*, than current IOU and third-party Demand Response Provider ("DRP") programs.

Question 3.3:

> *Should the Commission require new SGIP energy storage systems receiving any higher reliability incentive to be "future proof" (grid interactive, control system upgradeable over a network, able to respond to hourly or 15-minute or 5-minute real time prices, and able to participate in Virtual Power Plant aggregation services)? What steps should the Commission consider to support future-proofing energy storage systems?*

Response to Question 3.3:

MCE supports "future proofing" for all systems receiving enhanced SGIP incentives. MCE requires all ESS developers under MCE's Energy Storage Program to adhere to OpenADR 2.0b communication protocols to facilitate easier transition to other DERMS platforms and to avoid reliance on proprietary command and control communications protocols. To the extent practicable, the Commission should require open-source protocols to maximize customer choice and flexibility to change aggregators or LSEs without jeopardizing ongoing participation in peak load reduction programs.

MCE also supports use of 5-minute interval data to facilitate potential future participation in wholesale market programs and/or real-time pricing programs and to maximize peak load reduction opportunities.

Finally, MCE also recommends consideration of a performance-based incentive payment structure for larger non-residential systems to ensure ongoing participation in peak load reduction programs.

Question 3.4:

*Should the Commission require SGIP host customers receiving any higher reliability incentive to provide annual hourly charge, discharge, and state of charge data to the California Energy Commission or researchers authorized by this Commission for summer reliability research purposes?*

Response to Question 3.4:

Yes, MCE believes the Commission should require data sharing to improve future reliability programs, so long as the data is anonymized and individual customer data is protected.

Question 4:

*Do you have other suggestions to increase the contribution of SGIP technologies to summer reliability?*

Response to Question 4:

MCE does not have any other suggestions to increase the contribution of SGIP technologies to summer reliability at this time but looks forward to working with the Commission and other stakeholders to address these important questions going forward.

## II. CONCLUSION

MCE thank the Commission the opportunity to comment on this important matter.

Dated: August 23, 2021

Respectfully submitted,

*/s/ Jana Kopyciok-Lande*

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**BEFORE THE PUBLIC UTILITIES COMMISSION**
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| Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues. | Rulemaking 20-05-012<br>(Filed May 28, 2020) |

**COMMENTS OF MARIN CLEAN ENERGY ON HEAT PUMP WATER HEATER CONTRACTOR TRAINING AND WORKFORCE ISSUES AND METHODS TO INCREASE SELF-GENERATION INCENTIVE PROGRAM TECHNOLOGIES' CONTRIBUTIONS TO SUMMER RELIABLITY**


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August 23, 2021

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

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| Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues. | ) ) ) ) ) | Rulemaking 20-05-012 (Filed May 28, 2020) |

## COMMENTS OF MARIN CLEAN ENERGY ON HEAT PUMP WATER HEATER CONTRACTOR TRAINING AND WORKFORCE ISSUES AND METHODS TO INCREASE SELF-GENERATION INCENTIVE PROGRAM TECHNOLOGIES' CONTRIBUTIONS TO SUMMER RELIABLITY

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and Assigned Commissioner Rechtschaffen's August 3, 2021 *Assigned Commissioner's Ruling Requesting Comment on Heat Pump Water Heater Contractor Training and Workforce Issues and Methods to Increase Self-Generation Incentive Program Technologies' Contributions to Summer Reliability*, ("Ruling"), Marin Clean Energy ("MCE") hereby submits the following opening comments. In these comments, MCE responds to the Ruling's questions on the possible contribution from Self-Generation Incentive Program ("SGIP") technologies to summer reliability.

## I. COMMENTS

### A. Contribution from SGIP Technologies to Summer Reliability

Question 1:

> *Could higher SGIP incentives for certain SGIP budget and/or customer categories help contribute to grid reliability by summer 2022, by reducing peak loads? Which SGIP budget and/or customer categories have the greatest potential to contribute?*

Response to Question 1:

Higher, or "enhanced" SGIP incentives for certain SGIP budget and customer categories can help to contribute to grid reliability by summer 2022. Encouraging the large-scale expansion of deployed, customer-sided energy storage resources provide one of the best opportunities to reduce peak loads by summer 2022. Specifically, these technologies allow customers to charge during the mid-day period, when ample solar generation is available, and use this energy during the afternoon and evening peak demand periods. MCE believes that all SGIP budget categories that provide funding for customer-sided energy storage resources have the potential to make this contribution, including: the Large-Scale Storage, Small Residential Storage, Residential Storage Equity, Non-Residential Storage Equity, and Equity Resiliency budgets.

However, for these budget categories to reap benefits from additional incentives by summer 2022, three barriers must be overcome. First, Program Administrators ("PA") must quickly process and approve both currently pending applications and applications for any new incentives to ensure that all resources are fully deployed before summer 2022. Second, the Commission, PAs, Vendors, and all interested parties must work together to address the current energy storage supply chain issues resulting from the global pandemic (and the resulting backlog of existing installations). Third, increased demand for energy storage, largely in reaction to wildfires, climate change, and de-energizations and supply chain issues have resulted in higher labor and material costs for energy storage. Any additional incentives should take into account these higher costs, which could linger well into 2022 and beyond.

Question 2:

> *If higher SGIP incentives are offered to help contribute to grid reliability by summer 2022, should customers receiving the incentive be required to participate in a demand response aggregation program, or other demand response program? If so, which existing or proposed demand response programs should they be required to participate in? How long should participation be required? If higher incentives are offered, what amount do you recommend?*

Response to Question 2:

Customers who receive "enhanced" SGIP incentives to support grid reliability should be required to participate in a demand response ("DR") program that reduces peak load. Using higher incentives to increase DR program participation will help to ensure that the energy storage resources funded by enhanced SGIP incentives are used in a manner that maximizes grid reliability.

However, MCE urges the Commission to be flexible about the specific DR program that a customer must enroll in. In particular, customers of Community Choice Aggregators ("CCA") must be allowed to meet this requirement by participating in any of their CCA's DR programs, as long as the CCA DR program in question contributes to peak load reduction during the state's peak period of 4pm to 9pm. Further, if a CCA offers one or more relevant DR programs, these program(s) should be treated as the customer's "default" option(s), with participation in any IOU program limited to customers who opt out of the CCA's DR program.

It is essential that CCA customers are not defaulted into participation into an investor-owned utility ("IOU") DR program, as under DR program dual-participation rules found in the IOU tariffs, any resource that enrolls in an IOU DR program cannot enroll in any other DR program, including CCA DR programs.[1] This prohibition applies even if the two DR programs are not "competing" programs. Defaulting CCA customers into IOU DR programs would hence be

[1] *See*, PG&E Electric Rule 24, SCE Electric Rule 24, SDG&E Electric Rule 32.

anti-competitive, allowing the IOUs to use eligibility for SGIP incentives to block customer participation in CCA DR programs. Further, as required by the CCA Code of Conduct, IOUs should not be allowed to market against customer participation in competing CCA DR programs or use SGIP or DR funds to encourage CCA customers to opt out of CCA DR programs.

MCE has DR programs that would be ideal for many customers that would receive enhanced SGIP funding for grid reliability. For example, MCE's *Energy Storage Program*[2] offers performance-based compensation to participating customers in exchange for allowing MCE to directly monitor and control their energy storage systems ("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, both residential and non-residential, are aggregated into a virtual power plant ("VPP") and can also be manually dispatched in response to a California Independent System Operator ("CAISO") signal for emergency load reduction. At this point in time, the program is designed as a "load modifying resource" program, i.e., the participating resources are not participating directly in the CAISO market.

MCE also launched its *Peak Demand FLEXmarket*[3] program for the summer of 2021 that pays aggregators for shifting loads out of the peak period at the avoided cost of peak capacity (currently \$150/MWh), including higher payments (between \$200 - \$800/MWh) for up to 60 hours of load-shifting during event days when the grid is extremely constrained. The program does not prescribe the type of load reduction, allowing the market to respond with a variety of resource types, including electric vehicle charging, energy storage, smart thermostats/appliances, or

[2] Read more at https://www.mcecleanenergy.org/resiliency/
[3] Read more at https://www.mcecleanenergy.org/news/press-releases/mce-launches-new-grid-responsive-demand-flexmarket/

traditional demand response. Customers participating or enrolling in CCA programs such as these should not be forced to enroll in an IOU DR program or be precluded in any way from participating in a LSE-offered load reduction program.

Regarding the enhanced incentive levels for SGIP grid reliability resources, MCE recommends that the Commission adopt two distinct approaches for residential and non-residential customers, respectively. For residential customers, SGIP incentives are currently provided as a one-time, up-front rebate for residential storage systems based on the storage capacity being installed. The current incentive levels in Pacfic Gas & Electric's ("PG&E") service territory are as follows:

- Small Residential Storage - $0.20/Wh
- Residential Storage Equity - $0.85/Wh
- Equity Resiliency - $1/Wh

MCE supports continuing this approach for the enhanced incentives. The incentive for Residential Storage Equity and Equity Resiliency should be adjusted so that the incentives offered are at or near 100% current market price for an installed home energy storage storage system. The incentive for Small Residential Storage should likewise receive a meaningful upward adjustment to further incentivize residential customers in the general market to install energy storage systems.

For non-residential customers, MCE recommends that enhanced intentives include two elements. First, the enhanced incentives should increase the current up-front incentives for Large-Scale Storage, Non-Residential Storage Equity, and non-residential customers participating in the Equity Resliliency budget. Second, these customers should be offered a performance-based incentive payment based on the metered output from the ESS during peak periods. The specific amount of this performance-based SGIP incentive should be calculated based on the avoided cost of capacity needed to meet peak load.

As mentioned above, both residential and non-residential customers receiving enhanced SGIP benefits would be required to enroll in a peak load reducing DR program. Depending on the type of DR program, the customer may also receive additional payment for reducing load during peak hours from the respective DR program. However, payments for load reduction under the various DR programs vary greatly and can be minimal or non-existent for residential DR programs. Hence, MCE recommends that the enhanced SGIP incentive is set high enough to encourage customer participation under DR programs without relying on the incentives provided under the respective DR program.

Finally, MCE would like to point out that it is critical that energy storage customers who receive enhanced SGIP incentives for grid reliability should be required to enroll in DR programs that are "resiliency compatible." Resiliency Compatible DR programs would be defined as those programs that certify in writing that they will take reasonable steps to ensure that resiliency customer's batteries are fully charged prior to the commencement of any PSPS outage event, planned outage, or other high outage-risk conditions.

Question 3.1:

> *Should the Commission require new SGIP storage systems receiving any higher reliability incentive to enroll in a market-integrated residential or non-residential demand response program, the recently adopted out-of-market Emergency Load Reduction Program (ELRP), or a dynamic rate option (such as Critical Peak Pricing (CPP), or Real Time Pricing (RTP)? Should such a requirement be tied to higher incentives? If so, what amount?*

Response to Question 3.1:

For all enhanced SGIP storage budget categories, the Commission should require participation in a peak load reduction DR program. However, the Commission should *not* be prescriptive as to the type of program beyond requiring it to reduce peak loads. As previously noted, MCE's Energy Storage Program provides peak load reduction via direct control using

MCE's DERMS platform. Therefore, requiring participation in any type of IOU DR program or rate will severely impact MCE's program in a negative way due to the dual participation limitations described above.

See above suggestion for a method of calculating an appropriate incentive level.

Question 3.2:

*Should new residential SGIP energy storage participants with solar receiving any higher reliability incentive be required to select a Virtual Power Plant aggregator and participate in the ELRP? Are there any downsides to the Commission requiring default enrollment into ELRP for new SGIP energy storage participants receiving a higher reliability incentive?*

Response to Question 3.2:

MCE agrees with the notion that existing solar customers who add storage offer the greatest potential value for peak load reduction and that they should be either required to select a Virtual Power Plant aggregator or directly participate in a DR program. However, MCE strongly opposes requiring customers to participate in the existing Emergency Load Reduction Program ("ELRP") but instead supports requiring customers to participate in a DR program offered by any load-serving entity ("LSE") or CCA that targets peak load reduction (if available). MCE strongly urges the Commission to avoid being overly prescriptive regarding which DR program customers must enroll under as this would be detrimental to non-IOU DR/load reduction programs such as MCE's Energy Storage Program and Peak Demand FLEXmarket Program, which could be as effective, or *more effective*, than current IOU and third-party Demand Response Provider ("DRP") programs.

Question 3.3:

*Should the Commission require new SGIP energy storage systems receiving any higher reliability incentive to be "future proof" (grid interactive, control system upgradeable over a network, able to respond to hourly or 15-minute or 5-minute real time prices, and able to participate in Virtual Power Plant aggregation services)? What steps should the Commission consider to support future-proofing energy storage systems?*

Response to Question 3.3:

MCE supports "future proofing" for all systems receiving enhanced SGIP incentives. MCE requires all ESS developers under MCE's Energy Storage Program to adhere to OpenADR 2.0b communication protocols to facilitate easier transition to other DERMS platforms and to avoid reliance on proprietary command and control communications protocols. To the extent practicable, the Commission should require open-source protocols to maximize customer choice and flexibility to change aggregators or LSEs without jeopardizing ongoing participation in peak load reduction programs.

MCE also supports use of 5-minute interval data to facilitate potential future participation in wholesale market programs and/or real-time pricing programs and to maximize peak load reduction opportunities.

Finally, MCE also recommends consideration of a performance-based incentive payment structure for larger non-residential systems to ensure ongoing participation in peak load reduction programs.

Question 3.4:

> *Should the Commission require SGIP host customers receiving any higher reliability incentive to provide annual hourly charge, discharge, and state of charge data to the California Energy Commission or researchers authorized by this Commission for summer reliability research purposes?*

Response to Question 3.4:

Yes, MCE believes the Commission should require data sharing to improve future reliability programs, so long as the data is anonymized and individual customer data is protected.

Question 4:

> *Do you have other suggestions to increase the contribution of SGIP technologies to summer reliability?*

Response to Question 4:

MCE does not have any other suggestions to increase the contribution of SGIP technologies to summer reliability at this time but looks forward to working with the Commission and other stakeholders to address these important questions going forward.

## II. CONCLUSION

MCE thank the Commission the opportunity to comment on this important matter.

Dated: August 23, 2021

Respectfully submitted,

*/s/ Jana Kopyciok-Lande*

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

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

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
MOTION TO MODIFY SCOPE TO CONFORM TO GOVERNMENT CODE §16429.5**

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**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S MOTION TO MODIFY SCOPE TO CONFORM TO GOVERNMENT CODE §16429.5**

Pursuant to Rule 11.1(b) of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), California Community Choice Association[1] (CalCCA) respectfully makes this *Motion to Modify Scope to Conform to Government Code §16429.5* (Motion).

## I. INTRODUCTION

The Commission issued its Order Instituting Rulemaking (OIR) on February 17, 2021, in the midst of the ongoing COVID-19 pandemic.[2] The Commission aims to address, through the development of relief mechanisms and arrearage relief, the large and growing customer debt of utility and Community Choice Aggregator (CCA) customers.[3] Included in the scope of the OIR is an issue critical to the provision of relief to customers under the recently enacted California

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

2 *Order Instituting Rulemaking,* Rulemaking R.21-02-014 (issued Feb. 17, 2021) (OIR).

3 *Id.* at 2 ("This proceeding will examine the need for arrearage relief tied to the COVID-19 period, with consideration of appropriate parameters, cost estimates, and potential funding sources.").

Arrearage Payment Program (CAPP).[4] As originally articulated in the OIR, the Commission intends to examine "how might arrearage relief impact utility relationships with…[CCAs] and their customers."[5] The March 15, 2021 Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo) further refines the issue, seeking to address in Issue 7: (1) whether and how to allocate arrearage relief to CCA customers; and (2) whether to maintain a process for allocating partial payments on past due accounts first to satisfy a customer's past due utility debt before allocating any such payments to a CCA (the "Waterfall").[6]

The Legislature addressed these two questions directly in enacting Assembly Bill (AB) 135 (Budget Trailer) on July 16, 2021, creating the CAPP program in Government Code section 16429.5.[7] Section 16429.5(g) requires an investor-owned utility (IOU) to credit CAPP funding against customer charges owing the IOU and a CCA "in proportion to their respective shares of customer arrearages."[8] Section 16429.5(f)(4) further requires the IOU "to allocate any partial payments made by customers to the utility and other load serving entities in proportion to their respective shares of the outstanding customer charges."[9]

AB 135, through Section 16429.5(a), delegates authority to implement these and other provisions of the CAPP to the California Department of Community Services and Development (CSD).[10] Consequently, the Commission does not have the authority to move forward with Issue 7 as it relates to CAPP but must defer to the legislative directive and CSD's implementation.

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4 Cal. Gov't Code §16429.5.

5 OIR at 23.

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

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

8 Cal. Govt. Code §16429.5(g).

9 *Id.* §16429.5(f)(4).

10 *Id.* §16429.5(a).

Moreover, continuing to advance Issue 7 in this proceeding could slow the distribution of CAPP funds to customers. The current schedule of this proceeding contemplates a proposed decision sometime in October 2021,[11] which would lead to a final decision and implementation in November. While the final date for submission of an IOU application to CSD for relief is December 6, 2021,[12] CSD has indicated it will process applications on a rolling basis prior to the final submission date, leaving an opportunity for disbursement before the January 31, 2022 statutory deadline. A November final decision would therefore leave little, if any, opportunity for an IOU to submit its application prior to December 6.

For these reasons, CalCCA requests removal from the scope of this proceeding the two questions identified as Issue 7, to the extent they pertain to CAPP. To the extent the Issue 7 questions need to be addressed in the context of other state or federal COVID-19 relief programs, the Commission should retain them for consideration. Additionally, any further questions surrounding allocation of past due payments may need to be considered more broadly in the Disconnections rulemaking, R.18-05-003.

## II. PROCEDURAL BACKGROUND

The Issue 7 questions – allocation of past due payments between IOUs and CCAs and the allocation of relief funds – have been contemplated, but not resolved in this rulemaking as the COVID pandemic drags on and the source and amount of relief for the substantial customer debt is considered in various venues. The Waterfall has been suspended temporarily multiple times by the Commission, with the latest ruling extending the suspension of the Waterfall through

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11 *See Assigned Commissioner's and Administrative Law Judge's Ruling Amending Scope,* R.21-02-014 (July 29, 2021) (Amended Scoping Ruling) at 9; *see also E-Mail Ruling Correcting Schedule and Due Dates of Comments in Administrative Law Judge Rulings Dated July 29, 2021,* R.21-02-014 (Aug.3, 2021) (E-Mail Ruling) at 4.

12 *CAPP Program Notice No. 2021-01* (July 19, 2021) (CAPP Program Notice) at 3 (CAPP Applications due 60 days after release of Utility Survey).

September 30, 2021. With the passage of the CAPP legislation, the Waterfall and CAPP customer bill relief are being addressed by CSD.

### A. The Commission Suspended the Past Due Payment Waterfall at the Outset of the COVID-19 Pandemic and Has Extended it to September 30, 2021

The Waterfall is embedded in the IOU tariffs. As a part of the Commission's COVID-19 disconnection moratorium, the suspension of the Waterfall has been extended three times, most recently to September 30, 2021.

PG&E Rule 23.R.2. establishes a general rule for proportional allocation of partial payments by residential customers.

> Except as provided below in Section 3, if a customer makes only a partial payment for a service account, the payment shall be allocated proportionally between PG&E's charges and the CCA's charges.

PG&E Rule 23.R.3 includes the Waterfall language for past due payments to be allocated first to PG&E. SCE's Rule 23.R.2, also allocates to the IOU first:

> Partial payments by customers shall be allocated on a pro rata basis ***to SCE*** charges for which delinquency may result in disconnection, and then any balance shall be prorated between the CCA and other SCE charges.

SDG&E's Rule 27.R.2 articulation is virtually identical to SCE's articulation in Rule 23.

The Waterfall suspensions were implemented through IOU advice letter. The Commission issued Resolution M-4842 on April 16, 2020, ordering all utilities to suspend customer disconnections and requiring each IOU to file an implementation advice letter. Among earlier versions of its advice letters, PG&E filed Advice 4244-G/5816-E, on May 1, 2020. The advice letter responded to CalCCA's protest, which sought suspension of the Waterfall. PG&E explained:

> PG&E and CalCCA agree on a proposal for PG&E to suspend the allocation method for partial payments relating to past due accounts under Electric Rule 23.R.3 for a limited period due to COVID-19.

> According to this proposal, PG&E will allocate partial payments received from residential CCA customers on a pro rata basis with CCAs for up to one year, through April 16, 2021, and track any associated uncollectibles through the CPPMA for future recovery as described in Section D of this advice letter. PG&E will resume allocation of payments from residential CCA customers in accordance with Electric Rule 23.R.3 starting April 17, 2021. PG&E and CalCCA will monitor and meet to discuss any potential impacts this proposal may have on customers, and PG&E reserves the right to request modifications due to the uncertainty associated with the COVID-19 pandemic.

Advice 4244-G/5816-E was approved by the Energy Division.

As the pandemic continued, the Commission issued Resolution M-4849 on February 11, 2021, extending the protections directed in Resolution M-4842:

> Therefore, due to the continued economic harm from the COVID-19 pandemic, the Commission extends to California customers the Emergency Customer Protections from D.19-07-015 and D.19-08-025, as ordered by Resolution M-4842, through June 30, 2021, and the Commission reserves an option to extend.

In response, PG&E filed Advice 4388-G/6092-E extending its COVID-19 protections through June 30, 2021. Among other things, PG&E highlighted a change to Rule 23 as follows:

> Revising footnote to Section R.3 of Electric Rule 23 to note that due to the COVID-19 pandemic and pursuant to CPUC Resolutions M-4842 and M-4849, PG&E has suspended Section R.3 of Electric Rule 23 and will allocate partial payments received from residential CCA customers on a pro rata basis with CCAs for up to one year, through June 30, 2021, as described in Advice 4244-G/ 5516-E and Advice 4388-G/6092-E.[13]

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[13] PG&E Rule 23.R. has a footnote which reads:

> Due to the COVID-19 pandemic and pursuant to CPUC Resolutions M-4842 and M-4849, PG&E has suspended Section R.3 of Electric Rule 23 and will allocate partial payments received from residential CCA customers on a pro rata basis with CCAs for up to one year, through June 30, 2021, as described in Advice 4244-G-A/5516-E-A and Advice 4388-G/6092-E.

SDG&E's circumstances are similar to PG&E's. Most recently, Advice 3716-E/2961-G confirmed its treatment. SDG&E explained:

> D.19-07-015 directs SDG&E to coordinate with community choice aggregators (CCAs) during disasters to share information on affected customers. Consistent with its discussion with the CCAs in SDG&E's service territory, SDG&E suspended the allocation method for partial payments under Rule 27R.2 for CCA customers on payment plans implemented pursuant to the emergency customer protections for a limited period. During this period, SDG&E has allocated partial payments from CCA customers on a pro rata basis between SDG&E charges and CCA charges. Any associated uncollectibles resulting from this temporary adjustment will be tracked through the CPPMA for future recovery.

SCE responded to the Commission's directives by implementing, to the CCAs' satisfaction, a "zig zag" approach whereby past due payments are allocated alternately to SCE and then to the CCA, effectively resulting in a pro rata allocation of the payments.[14]

Absent Commission action, the IOUs would have resumed their "utility first" partial payment allocation methodologies on July 1, 2021. In its Phase I Decision, however, the Commission extended the suspension of the Waterfall through September 30, 2021, slating the "permanent determination" of the Waterfall issue for Phase II of the proceeding.[15]

### B. The Commission Intended to Address Allocation of Relief Funds to, and Past Due Payments from, Customers in this Rulemaking

The Commission first articulated Issue 7 very generally in the OIR:

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[14] *See* SCE Advice Letter 233-G/4205-E (May 1, 2020) (describing SCE's customer protections in response to Resolution M-4842 and noting that SCE had suspended disconnections for nonpayment, and that SCE was "closely coordinat[ing] with CCAs in its service territory about the various consumer protections and discuss issues that will likely have financial and/or operational impacts to the CCAs"); SCE Advice Letter 239-G/4423-E (Feb. 22, 2021) (SCE's extension of emergency customer protections to June 30, 2021, and noting the continued operational and financial coordination with CCAs).

[15] *Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* D.21-06-036, June 30, 2021 (Phase I Decision) at 32-33.

> How might arrearage relief impact utility relationships with Core Transport Agents, Energy Service Providers, and Community Choice Aggregators, and their customers?[16]

The Commission refined this issue in pertinent part in its Scoping Memo:

> 7. Should arrearage relief be applied to . . .CCA customers? If so, how?
>
>    . . .
>
>    b. To the extent that customers are not at risk of disconnection for failure to pay their CCA charges, does this change the need for arrearage relief of CCA charges?
>    c. To what extent does Public Utilities Code Section 779.2 require utilities to allocate partial payments first to disconnectable charges?[17]

The Commission issued its Phase I Decision (D.) 21-06-036 on June 24, 2021, requiring utilities to automatically enroll customers in arrears into long-term payment plans. The Commission also extended the moratorium on disconnections for nonpayment through September 30, 2021.[18] Finally, the Commission extended the temporary suspension of the Waterfall through September 30, 2021.[19]

In its July 29, 2021 Amended Scoping Ruling, the July 29, 2021 Ruling Setting Joint Status Conference and Ordering Comments (JSC Ruling),[20] and the August 3, 2021 E-Mail Ruling (collectively, the Phase II Rulings), the Commission again addressed Issue 7. The Amended Scoping Ruling includes two related questions among the issues to be addressed in Phase II of the proceeding:

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16 OIR at 23.

17 Scoping Memo at 6-7.

18 Id.at 50.

19 *Id.* at 52.

20 *Ruling Setting Joint Status Conference and Ordering Comments,* R.21-02-014 (July 29, 2021) (JSC Ruling).

> a. Permanent determination of the allocations of partial payments on COVID-19 related arrearages to [sic];[21]
>
> b. Implementation issues, if any, relating to the new legislation affecting COVID-19 arrearage relief, including but not limited to the Budget Act, the Trailer Bill, and AB 832 enacted since D.21-06-036 was issued in June….[22]

The Amended Scoping Ruling clarifies further the Commission's intent to prioritize resolution of the question of how to allocate partial payments on arrearages between the IOUs and CCAs.[23]

The JSC Ruling, issued the same day, also incorporates the same issues, although it labels the issues as Section 3, rather than Issue 7. The Section 3 issues, however, are substantially identical to Issue 7:

> 3. Allocation of Payments on Past-Due Utility Bills Between [CCAs] and Utilities (Energy Stakeholders Only)
>
> 1. Should arrearage relief be applied to [CCA] customers? If so, how?
>
> a. To the extent that customers are not at risk of disconnection for their failure to pay their CCA charges, does this change the need for arrearage relief of CCA charges?[24]
>
> b. To what extent does Public Utilities Code Section 779.2 require utilities to allocate partial payments first to disconnectable charges?[25]

The Phase II Rulings set a due date of August 27, 2021 for briefs to be submitted on Issue 7.[26] A Proposed Decision on Issue 7 is scheduled for October 2021.[27]

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21 This incomplete language likely was intended to address allocations between IOUs and other LSEs, based on the context of prior rulings.

22 Amended Scoping Ruling at 8.

23 Amended Scoping Ruling at 2 (noting that D.21-06-036 "only temporarily resolved the issue of how to allocate partial payments on debt between energy utilities and CCAs").

24 JSC Ruling at 6.

25 *Id.* at 6.

26 See JSC Ruling at 3, 10 and E-Mail Ruling at 3.

27 See JSC Ruling at 9 and E-Mail Ruling at 4.

## III. THE COMMISSION'S ORIGINAL INTENT TO ADDRESS CCA CUSTOMER RELIEF ISSUES IN THIS RULEMAKING HAS BEEN PARTLY OVERTAKEN BY THE LEGISLATURE IN ENACTING CAPP

When the Commission instituted this rulemaking, the allocation of COVID-19 pandemic relief funds and past due payments remained fully within the scope of its jurisdiction. As the state's response to the crisis has unfolded, however, the Legislature has stepped in to address these questions for purposes of CAPP.

Prior to the Phase II Rulings, the Legislature passed AB 128 on June 28, 2021 which appropriated nearly $1 billion for arrearage relief for utility customers.[28] The Trailer Bill, AB 135, was signed by Governor Newsom on July 16, 2021, enacting CAPP and delegating oversight to CSD. Section 16429.5 of the Government Code provides a comprehensive scheme for CSD to allocate the $694,953,250 of the funds to "all distribution customers of investor-owned utilities, <u>including customers served by a CCA.</u>"[29] The statute speaks squarely to the questions articulated in Issue 7 in this rulemaking. Government Code section 16429.5(g) addresses original Issue 7.b. – allocation of relief funding – requiring the utilities to:

> credit funding received through CAPP against customer charges owing the utility and <u>all other load serving entities</u> serving the customer in proportion to their respective shares of customer arrearages.[30]

Section 16429.5(f)(4) addresses original Issue 7.c. – the Waterfall – requiring pro rata allocation of past due payments between the IOU and CCA.[31]

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[28] AB 128, Budget Act of 2021, Section 19.55, signed by Governor Newsom on June 28, 2021. *See* https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB128

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

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

[31] *Id.* §16429.5(f)(4).

The CSD has already begun its administration of the CAPP program, issuing its CAPP Program Notice and working with the IOUs and CCAs to refine the process in accordance with its statutory mandate. CSD has instituted a schedule pursuant to its CAPP Program Notice, with utility applications due on December 6, 2021, funds to be allocated by January 2022, and utility customers to receive credits on their arrearages by March 2022. CSD has indicated in meetings with the IOUs and CCAs, however, that it will process applications on a rolling basis to the extent a utility submits its application before the deadline.

## IV. THE COMMISSION MUST RECOGNIZE CSD'S JURISDICTION AND REMOVE FROM THIS PROCEEDING'S SCOPE THE ALLOCATION OF CAPP FUNDING TO CCAS AND THE ALLOCATION OF PAST DUE PAYMENTS FROM CCA CUSTOMERS

The issues contemplated by Issue 7 must be removed from the scope of this proceeding. CSD maintains jurisdiction over these issues in the context of CAPP, and any continued consideration by the Commission on the same issues would infringe on that jurisdiction. While the Commission has jurisdiction "to supervise and regulate every public utility in the state,"[32] when that jurisdiction is made concurrent with another California agency by another (especially a later) legislative enactment, the Commission must share its jurisdiction with that agency and defer when the statutory delegation is comprehensive and specific.[33] Here, the Legislature has provided a comprehensive program for the CSD to handle all aspects of the CAPP program. Specifically, the allocation of CAPP arrearage relief funding to CCA customers (7.b.) and the

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32 Cal. Pub. Util. Code §701.

33 *Orange County Air Pollution District v. Public Utilities Commission, et al.,* (1971) 4 Cal.3d 945, 953-54 (finding concurrent jurisdiction between the CPUC and an air pollution control board over a utility whose activities were regulated by both, and annulling a Commission decision overruling the air pollution control board's denial of approval over construction of a privately owned generator when the Legislature specifically delegated the specific emission control standards allowing the denial of such approval to that control board); *see also San Diego Gas & Elec. Co. v. City of Carlsbad,* (1998) 64 Cal.App.4th (the Commission's directives are not given controlling effect when jurisdiction conflicts with *other* than a local agency (such as another state agency)).

Waterfall (7.c.) have been statutorily resolved by AB 135 and the adoption of Government Code Section 16429.5. Accordingly, the Commission must remove from the scope of this proceeding any consideration or decision regarding the questions of Issue 7 in the context of CAPP. Failing to remove Issue 7 with respect to CAPP would cause the Commission to unlawfully impede upon the specific jurisdiction provided to the CSD to administer the CAPP program. In addition, such failure could potentially delay or impede the arrearage relief that this Rulemaking was intended to facilitate and that utility/CCA customers so desperately need.

## V. ISSUE 7 SHOULD BE RETAINED IN THIS PROCEEDING FOR CONSIDERATION IN THE CONTEXT OF OTHER RELIEF PROGRAMS OR CONSIDERED IN R.18-07-005

The questions raised in Issue 7 – allocation of relief funds and allocation of past due payments – may be relevant in contexts other than CAPP. Specifically, allocation of COVID relief to CCA customers in arrears through state or federal programs other than CAPP may need to be considered by the Commission. In addition, while AB 135 extended the suspension of the Waterfall through the administration of the CAPP program (therefore at least until March of 2022), a more appropriate venue to consider a permanent decision regarding the Waterfall would be in the current Disconnections rulemaking, R.18-07-005. Thus, while removing Issue 7 from this proceeding for purposes of CAPP, the Commission should include the issues in one or both of these related proceedings to address other potential relief programs.

## VI. CONCLUSION

CalCCA respectfully requests that the Commission take the following actions:

1) Remove from the scope of this proceeding the questions of Issue 7 in the context of CAPP, as a result of the statutory directive in Government Code Section 16429.5; and

2) Retain Issue 7 questions outside of the context of CAPP for consideration in this proceeding, or to the extent appropriate, in the Disconnections proceeding, R.18-07-005.

Respectfully submitted,

Evelyn Kahl

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

August 24, 2021

# Submit comment on Revised straw proposal

Initiative: Maximum import capability enhancements

**1. Provide a summary of your organization's comments on the Maximum Import Capability (MIC) Enhancements revised straw proposal:**

The California Community Choice Association (CalCCA) appreciates the opportunity to submit comments on the Maximum import capability (MIC) Enhancements Revised Straw Proposal. CalCCA generally supports the California Independent System Operator (CAISO's) proposal, specifically the proposal to enhance transparency to facilitate trades more easily and increase the usage of available MIC. CalCCA also requests the CAISO monitor and report out on the amount of MIC being locked in for long term use. These changes, coupled with the proposals contemplated in the Resource Adequacy Enhancements initiative that would replace substitution requirements and Resource Adequacy Availability Incentive Mechanism (RAAIM), will result in the efficient allocation and use of MIC.

**2. Provide your organization's comments on the improve transparency topic, as described in section 4.1:**

CalCCA supports the CAISO's proposal to improve transparency. The CAISO proposes to make data publicly available through a web interface identifying most up-to-date owners of MIC allocations at the branch group level including megawatt (MW) quantity, contact, and MWs available for trade and aggregate usage by branch group level after Resource Adequacy (RA) showings are submitted. Improvements to transparency will allow for load-serving entities (LSEs) to trade MIC more easily by identifying potential entities with MIC available to trade at different locations.

The Revised Straw Proposal asks whether the CAISO should aggregate of MIC usage by the California Public Utilities Commission (Commission) versus Non-Commission jurisdictional LSEs or provide a single aggregated number for all LSEs. CalCCA recommends the CAISO split the aggregation by Commission versus non-Commission jurisdictional LSEs so that if unused MIC is primarily attributable to LSEs under one group or the other, the appropriate local regulatory authority(ies) can investigate the primary causes of unused MIC for their LSEs.

In addition to providing the data proposed in the Revised Straw Proposal, the CAISO should also monitor and report out on the amount of multi-year MIC locked in by LSEs on specific branch groups. CalCCA does not take issue with the opportunity for LSEs to lock in longer-term MIC for multiple years as adopted in the MIC Stabilization and Multi-Year Allocation initiative but requests the CAISO monitor and report out on how much MIC is being locked in for multiple years to ensure adequate short-term MIC is also available. If in the future significant portions of MIC are locked in many years forward (including evergreen contracts), it could create challenges for LSEs year-long import contracts looking to secure MIC. The CAISO should monitor and report out on the amount multi-year MIC so stakeholders are aware of the amount of MIC that is locked in for future years.

**3. Provide your organization's comments on the education regarding deliverability of imports and internal resources topic, as described in section 4.2:**

No comments at this time.

**4. Provide your organization's comments on the MIC Capability expansion topic, as described in section 4.3:**

No comments at this time.

**5. Provide your organization's comments on the Step 13 - give priority to existing RA contracts topic, as described in section 4.4:**

No comments at this time.

**6. Provide your organization's comments on the Tariff and Reliability Requirements BPM alignment of terms topic, as described in section 4.5:**

No comments at this time.

**7. Provide your organization's comments on other issues that require further exploration, as described in section 4.6:**

In the Revised Straw Proposal, the CAISO lists several issues that the CAISO does not plan to move forward with or that require further exploration before moving forward with a proposal. These issues include developing an auction mechanism for allocating MIC, conducting deliverability studies after RA showings, releasing unused MIC, and changing the methodology for calculating MIC to include liquidity. CalCCA generally supports the CAISO's decision not to move forward with these changes at this time, given the current allocation process generally works well by allocating MIC to LSEs responsible for paying the costs of the transmission system and meeting RA obligations. A method that continues to allocate MIC to LSEs based on its load ratio share, coupled with improvements to transparency proposed in this initiative and the removal of substitution requirements and RAAIM contemplated in the RA Enhancements initiative, should result in efficient allocation and use of MIC.

**8. Provide your organization's comments on the proposed initiative schedule and EIM Governing Body role, as described in section 5:**

CalCCA continues to support the Energy Imbalance Market (EIM) Governing Body classification for this initiative.

**9. Additional comments on the Maximum Import Capability Enhancements revised straw proposal:**

No additional comments at this time.

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

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

(NOT CONSOLIDATED)

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

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S BRIEF ON SCOPED ISSUE 7, ALLOCATION OF PAYMENTS ON ARREARAGES FOR CCA CUSTOMERS**

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August 27, 2021

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## SUMMARY OF RECOMMENDATIONS

- ✓ Grant CalCCA's Motion to Modify Scope to Conform to Government Code §16429.5 (CalCCA Motion), filed August 24, 2021.
- ✓ If the Commission fails to act on or denies CalCCA's Motion, and therefore proceeds with consideration of Issue 7, the Commission should:
  - ➢ As it relates to CAPP, accelerate the schedule to complete consideration with a final decision not later than September 30 and find:
    - The methodologies currently employed by the IOUs for allocation of partial payments between IOUs and CCAs of past due balances conforms to the requirements of Government Code §16429.5(f)(4).
    - Consistent with Government Code §16429(g), each IOU must implement a methodology for allocation of any CAPP funds received by the IOU and both the IOU and the CCA must receive their proportionate share of funds on behalf of their customers; each load-serving entity's (LSE's) "proportionate" share is calculated by dividing an LSE's total CAPP-eligible balances in the "bucket" to which CSD disburses the funds by the combined CAPP-eligible balances in that bucket for both LSEs.
  - ➢ Retain jurisdiction to consider Issue 7 related to any state/federal COVID relief programs outside of CAPP.
  - ➢ Retain jurisdiction either in this proceeding or in the Disconnections rulemaking, R.18-07-005, to permanently decide on the Issue 7 question of the allocation of partial payments between IOUs and CCAs of past due balances.

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

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

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**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S BRIEF ON SCOPED ISSUE 7, ALLOCATION OF PAYMENTS ON ARREARAGES FOR CCA CUSTOMERS**

Pursuant to Rule 13.12 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, *Assigned Commissioner's Scoping Memo and Ruling,* March 15, 2021 (Scoping Memo), *Assigned Commissioner's and Administrative Law Judge's Ruling Amending Scope*, July 29, 2021 (Amended Scoping Ruling), *Ruling Setting Joint Status Conference and Ordering Comments*, July 29, 2021 (JSC Ruling), and *E-Mail Ruling Correcting Schedule and Due Dates of Comments in Administrative Law Judge Rulings Dated July 29, 2021*, August 3, 2021 (E-Mail Ruling), California Community Choice Association[1] (CalCCA) submits this Brief on Scoped Issue 7, Allocation of Payments on Arrearages of CCA Customers.

## I. INTRODUCTION

The Commission issued its Order Instituting Rulemaking (OIR) on February 17, 2021, in the midst of the ongoing COVID-19 pandemic.[2] The Commission aims to address, through the

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

[2] *Order Instituting Rulemaking,* Rulemaking (R.) 21-02-014 (issued Feb. 17, 2021) (OIR).

development of relief mechanisms and arrearage relief, the large and growing customer debt of utility and Community Choice Aggregator (CCA) customers.[3] Included in the scope of the OIR is an issue critical to the provision of relief to customers under the recently enacted California Arrearage Payment Program (CAPP).[4] As originally articulated in the OIR, the Commission intends to examine "how might arrearage relief impact utility relationships with…[CCAs] and their customers."[5] The Scoping Memo further refines the issue, seeking to address in Scoped Issue 7: (1) whether and how to allocate arrearage relief to CCA customers; and (2) whether to maintain a process for allocating partial payments on past due accounts first to satisfy a customer's past due utility debt before allocating any such payments to a CCA (the "Waterfall").[6]

The Legislature addressed these two questions directly in enacting Assembly Bill (AB) 135 (Budget Trailer) on July 16, 2021, creating the CAPP program in Government Code section 16429.5.[7] Section 16429.5(g) requires an IOU to credit CAPP funding against customer charges owing the IOU and a CCA "in proportion to their respective shares of customer arrearages."[8] Section 16429.5(f)(4) further requires the IOU "to allocate any partial payments made by customers to the utility and other load serving entities in proportion to their respective shares of the outstanding customer charges."[9]

AB 135, through section 16429.5(a), delegates authority to implement these and other provisions of the CAPP to the California Department of Community Services and Development (CSD).[10] Consequently, the Commission does not have the authority to move forward with Issue 7 as it relates to CAPP but must defer to the legislative directive and CSD's implementation. Moreover, continuing to advance Issue 7 in this proceeding could slow the distribution of CAPP funds to customers. The current schedule of this proceeding contemplates a proposed decision sometime in October 2021,[11] which would

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3 *Id.* at 2 ("This proceeding will examine the need for arrearage relief tied to the COVID-19 period, with consideration of appropriate parameters, cost estimates, and potential funding sources.").

4 Cal. Gov't Code §16429.5.

5 OIR at 23.

6 Scoping Memo at 6-7.

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

8 Cal. Govt. Code §16429.5(g).

9 *Id.* §16429.5(f)(4).

10 *Id.* §16429.5(a).

11 *See Assigned Commissioner's and Administrative Law Judge's Ruling Amending Scope,* R.21-02-014 (July 29, 2021) (Amended Scoping Ruling) at 9; *see also E-Mail Ruling Correcting Schedule and Due Dates of Comments in Administrative Law Judge Rulings Dated July 29, 2021,* R.21-02-014 (Aug.3, 2021) (E-Mail Ruling) at 4.

lead to a final decision and implementation in November. While the final date for submission of an IOU application to CSD for relief is December 6, 2021,[12] CSD has indicated it will process applications on a rolling basis prior to the final submission date, leaving an opportunity for disbursement before the January 31, 2022 statutory deadline. A November final decision would therefore leave little, if any, opportunity for an IOU to submit its application prior to December 6, 2021.

For these reasons, on August 24, 2021 CalCCA filed in this proceeding a Motion to Modify Scope to Conform to Government Code §16429.5,[13] requesting the removal from the scope of this proceeding the two questions identified as Issue 7, to the extent they pertain to CAPP. The CalCCA Motion also requested that to the extent the Scoped Issue 7 questions need to be addressed in the context of other state or federal COVID-19 relief programs, the Commission should retain them for consideration. Finally, the CalCCA Motion suggested that any further questions surrounding allocation of past due payments may need to be considered more broadly in the Disconnections rulemaking, R.18-07-005.

As stated in CalCCA's Motion, immediate removal from this proceeding of the two questions posed in Issue 7, to the extent those questions pertain to CAPP, will (1) ensure that the Commission appropriately and legally defers to the specific jurisdiction granted to CSD for the CAPP, and (2) ensure that the desperately needed arrearage relief will be distributed to customers in the accelerated timeframe already established by CSD.

Therefore, CalCCA again requests that the Commission Grant the CalCCA Motion for all of the reasons stated therein. If, however, the Commission fails to act on or denies CalCCA's Motion, and therefore proceeds with consideration of Issue 7, the Commission should:

- ➢ As it relates to CAPP, accelerate the schedule to complete consideration with a final decision not later than September 30 and find:
  - ▪ The methodologies currently employed by the IOUs for allocation of partial payments between IOUs and CCAs of past due balances conforms to the requirements of Government Code §16429.5(f)(4).
  - ▪ Consistent with Government Code §16429(g), each IOU must implement a methodology for allocation of any CAPP funds received by the IOU and both the IOU and the CCA must receive their proportionate share of funds on behalf of their customers; each load-serving entity's (LSE's) "proportionate"

12 *CAPP Program Notice No. 2021-01* (July 19, 2021) (CAPP Program Notice) at 3 (CAPP Applications due 60 days after release of Utility Survey).

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

share is calculated by dividing an LSE's total CAPP-eligible balances in the "bucket" to which CSD disburses the funds by the combined CAPP-eligible balances in that bucket for both LSEs.

- Retain jurisdiction to consider Issue 7 related to any state/federal COVID relief programs outside of CAPP.
- Retain jurisdiction either in this proceeding or in the Disconnections rulemaking, R.18-07-005, to permanently decide on the Issue 7 question, outside of CAPP, of the allocation of partial payments between IOUs and CCAs of past due balances.

## II. PROCEDURAL BACKGROUND

The Issue 7 questions – allocation of past due payments between IOUs and CCAs and the allocation of relief funds – have been contemplated, but not resolved in this rulemaking as the COVID pandemic continues and the source and amount of relief for the substantial customer debt is considered in various venues. The Waterfall has been suspended temporarily multiple times by the Commission, with the latest ruling extending the suspension of the Waterfall through September 30, 2021. With the passage of the CAPP legislation, the Waterfall and CAPP customer bill relief are being addressed by CSD in accordance with Government Code section 16429.5.

### A. The Commission Suspended the Past Due Payment Waterfall at the Outset of the COVID-19 Pandemic and Has Extended it to September 30, 2021

The Waterfall is embedded in the IOU tariffs. As a part of the Commission's COVID-19 disconnection moratorium, the suspension of the Waterfall has been extended three times, most recently to September 30, 2021.

PG&E Rule 23.R.2. establishes a general rule for proportional allocation of partial payments by residential customers.

> Except as provided below in Section 3, if a customer makes only a partial payment for a service account, the payment shall be allocated proportionally between PG&E's charges and the CCA's charges.

PG&E Rule 23.R.3 includes the Waterfall language for past due payments to be allocated first to PG&E. SCE's Rule 23.R.2, also allocates to the IOU first:

> Partial payments by customers shall be allocated on a pro rata basis ***to SCE*** charges for which delinquency may result in disconnection, and then any balance shall be prorated between the CCA and other SCE charges.

SDG&E's Rule 27.R.2 articulation is virtually identical to SCE's articulation in Rule 23.R.2.

The Waterfall suspensions were implemented through IOU advice letters. The Commission issued Resolution M-4842 on April 16, 2020, ordering all utilities to suspend customer disconnections and requiring each IOU to file an implementation advice letter. Among earlier versions of its advice letters, PG&E filed Advice 4244-G/5816-E, on May 1, 2020. The advice letter responded to CalCCA's protest, which sought suspension of the Waterfall. PG&E explained:

> PG&E and CalCCA agree on a proposal for PG&E to suspend the allocation method for partial payments relating to past due accounts under Electric Rule 23.R.3 for a limited period due to COVID-19. According to this proposal, PG&E will allocate partial payments received from residential CCA customers on a pro rata basis with CCAs for up to one year, through April 16, 2021, and track any associated uncollectibles through the CPPMA for future recovery as described in Section D of this advice letter. PG&E will resume allocation of payments from residential CCA customers in accordance with Electric Rule 23.R.3 starting April 17, 2021. PG&E and CalCCA will monitor and meet to discuss any potential impacts this proposal may have on customers, and PG&E reserves the right to request modifications due to the uncertainty associated with the COVID-19 pandemic.

Advice 4244-G/5816-E was approved by the Energy Division.

As the pandemic continued, the Commission issued Resolution M-4849 on February 11, 2021, extending the protections directed in Resolution M-4842:

> Therefore, due to the continued economic harm from the COVID-19 pandemic, the Commission extends to California customers the Emergency Customer Protections from D.19-07-015 and D.19-08-025, as ordered by Resolution M-4842, through June 30, 2021, and the Commission reserves an option to extend.

In response, PG&E filed Advice 4388-G/6092-E extending its COVID-19 protections through June 30, 2021. Among other things, PG&E highlighted a change to Rule 23 as follows:

> Revising footnote to Section R.3 of Electric Rule 23 to note that due to the COVID-19 pandemic and pursuant to CPUC Resolutions M-4842 and M-4849, PG&E has suspended Section R.3 of Electric Rule 23 and will allocate partial payments received from residential CCA customers on a pro rata basis with CCAs for up to one year, through June 30, 2021, as described in Advice 4244-G/ 5516-E and Advice 4388-G/6092-E.[14]

[14] PG&E Rule 23.R. has a footnote which reads: Due to the COVID-19 pandemic and pursuant to CPUC Resolutions M-4842 and M-4849, PG&E has suspended Section R.3 of Electric Rule 23 and will allocate partial payments received from residential CCA customers on a pro rata basis with CCAs for up to one year, through June 30, 2021, as described in Advice 4244-G-A/5516-E-A and Advice 4388-G/6092-E.

SDG&E's circumstances are similar to PG&E's. Most recently, Advice 3716-E/2961-G confirmed its treatment. SDG&E explained:

> D.19-07-015 directs SDG&E to coordinate with community choice aggregators (CCAs) during disasters to share information on affected customers. Consistent with its discussion with the CCAs in SDG&E's service territory, SDG&E suspended the allocation method for partial payments under Rule 27R.2 for CCA customers on payment plans implemented pursuant to the emergency customer protections for a limited period. During this period, SDG&E has allocated partial payments from CCA customers on a pro rata basis between SDG&E charges and CCA charges. Any associated uncollectibles resulting from this temporary adjustment will be tracked through the CPPMA for future recovery.

SCE responded to the Commission's directives by implementing, to the CCAs' satisfaction, a "zig zag" approach whereby past due payments are allocated alternately to SCE and then to the CCA, effectively resulting in a pro rata allocation of the payments.[15]

Absent Commission action, the IOUs would have resumed their "utility first" partial payment allocation methodologies on July 1, 2021. In its Phase I Decision, however, the Commission extended the suspension of the Waterfall through September 30, 2021, slating the "permanent determination" of the Waterfall issue for Phase II of the proceeding.[16]

### B. The Commission Intended to Address Allocation of Relief Funds to, and Past Due Payments from, Customers in this Rulemaking

The Commission first articulated Issue 7 very generally in the OIR:

> How might arrearage relief impact utility relationships with Core Transport Agents, Energy Service Providers, and Community Choice Aggregators, and their customers?[17]

The Commission refined this issue in pertinent part in its Scoping Memo:

> 7. Should arrearage relief be applied to . . .CCA customers? If so, how?
>
> . . .

15 *See* SCE Advice 233-G/4205-E (May 1, 2020) (describing SCE's customer protections in response to Resolution M-4842 and noting that SCE had suspended disconnections for nonpayment, and that SCE was "closely coordinat[ing] with CCAs in its service territory about the various consumer protections and discuss[ing] issues that will likely have financial and/or operational impacts to the CCAs"); SCE Advice 239-G/4423-E (Feb. 22, 2021) (SCE's extension of emergency customer protections to June 30, 2021, and noting the continued operational and financial coordination with CCAs).

16 *Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* D.21-06-036, June 30, 2021 (Phase I Decision) at 32-33.

17 OIR at 23.

b. To the extent that customers are not at risk of disconnection for failure to pay their CCA charges, does this change the need for arrearage relief of CCA charges?

c. To what extent does Public Utilities Code Section 779.2 require utilities to allocate partial payments first to disconnectable charges?[18]

The Commission issued its Phase I Decision (D.) 21-06-036 on June 24, 2021, requiring utilities to automatically enroll customers in arrears into long-term payment plans.[19] The Commission also extended the moratorium on disconnections for nonpayment through September 30, 2021.[20] Finally, the Commission extended the temporary suspension of the Waterfall through September 30, 2021.[21]

In its July 29, 2021 Amended Scoping Ruling, the July 29, 2021 JSC Ruling, and the August 3, 2021 E-Mail Ruling (collectively, the Phase II Rulings), the Commission again addressed Issue 7. The Amended Scoping Ruling includes two related questions among the issues to be addressed in Phase II of the proceeding:

a. Permanent determination of the allocations of partial payments on COVID-19 related arrearages to [sic];[22]

b. Implementation issues, if any, relating to the new legislation affecting COVID-19 arrearage relief, including but not limited to the Budget Act, the Trailer Bill, and AB 832 enacted since D.21-06-036 was issued in June….[23]

The Amended Scoping Ruling clarifies further the Commission's intent to prioritize resolution of the question of how to allocate partial payments on arrearages between the IOUs and CCAs.[24]

The JSC Ruling, issued the same day, also incorporates the same issues, although it labels the issues as Section 3, rather than Issue 7.[25] The Section 3 issues, however, are substantially identical to Issue 7:

3. Allocation of Payments on Past-Due Utility Bills Between [CCAs] and Utilities (Energy Stakeholders Only)

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18 Scoping Memo at 6-7.

19 Phase 1 Decision at 50-52.

20 *Id*. at 50.

21 *Id*. at 52.

22 This incomplete language likely was intended to address allocations between IOUs and other LSEs, based on the context of prior rulings.

23 Amended Scoping Ruling at 8.

24 Amended Scoping Ruling at 2 (noting that D.21-06-036 "only temporarily resolved the issue of how to allocate partial payments on debt between energy utilities and CCAs").

25 JSC Ruling at 6.

1. Should arrearage relief be applied to [CCA] customers? If so, how?
    a. To the extent that customers are not at risk of disconnection for their failure to pay their CCA charges, does this change the need for arrearage relief of CCA charges?
    b. To what extent does Public Utilities Code Section 779.2 require utilities to allocate partial payments first to disconnectable charges?[26]

The Phase II Rulings set a due date of August 27, 2021 for briefs to be submitted on Issue 7.[27] A Proposed Decision on Issue 7 is scheduled for October 2021.[28]

## III. THE COMMISSION'S ORIGINAL INTENT TO ADDRESS CCA CUSTOMER RELIEF ISSUES IN THIS RULEMAKING HAS BEEN PARTLY OVERTAKEN BY THE LEGISLATURE IN ENACTING CAPP

When the Commission instituted this rulemaking, the allocation of COVID-19 pandemic relief funds and past due payments remained fully within the scope of its jurisdiction. As the state's response to the crisis has unfolded, however, the Legislature has stepped in to address these questions for purposes of CAPP.

Prior to the Phase II Rulings, the Legislature enacted AB 128 on June 28, 2021 which appropriated nearly $1 billion for arrearage relief for utility customers.[29] The Trailer Bill, AB 135, was signed by Governor Newsom on July 16, 2021, enacting CAPP and delegating oversight to CSD. Section 16429.5 of the Government Code provides a comprehensive scheme for CSD to allocate the $694,953,250 of the funds to "all distribution customers of investor-owned utilities, <u>including customers served by a CCA.</u>"[30] The statute speaks squarely to the questions articulated in Issue 7 in this rulemaking. Government Code section 16429.5(g) addresses original Issue 7.b. – allocation of relief funding – requiring the utilities to:

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26 *Id.* at 6.

27 See *Id.* at 3, 10 and E-Mail Ruling at 3.

28 See JSC Ruling at 9 and E-Mail Ruling at 4.

29 AB 128, Budget Act of 2021, Section 19.55, signed by Governor Newsom on June 28, 2021. *See* https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB128

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

> credit funding received through CAPP against customer charges owing the utility and all other load serving entities serving the customer in proportion to their respective shares of customer arrearages.[31]

Section 16429.5(f)(4) addresses original Issue 7.c. – the Waterfall – requiring pro rata allocation of past due payments between the IOU and CCA. [32]

The CSD has already begun its administration of the CAPP program, issuing its CAPP Program Notice and working with the IOUs and CCAs to refine the process in accordance with its statutory mandate. CSD has instituted a schedule pursuant to its CAPP Program Notice, with utility applications due on December 6, 2021, funds to be allocated by January 2022, and utility customers to receive credits on their arrearages by March 2022. CSD has indicated in meetings with the IOUs and CCAs, however, that it will process applications on a rolling basis to the extent a utility submits its application before the deadline.

CalCCA filed the CalCCA Motion to remove these issues from consideration in this proceeding. They fall squarely within CSD's jurisdiction under Government Code section 16429.5.[33] Most importantly, waiting to consider these important issues to comport with the current schedule in this proceeding will hamper the IOUs' ability to get their applications processed and procedures implemented and thus delay needed relief to customers. The Commission should thus grant the motion and remove Issue 7 as it pertains to CAPP from the scope of this proceeding.

## IV. IF THE COMMISSION PROCEEDS WITH CONSIDERATION OF ISSUE 7 AS IT RELATES TO CAPP, THE COMMISSION SHOULD ACCELERATE THE SCHEDULE TO COMPLETE CONSIDERATION NOT LATER THAN SEPTEMBER 30 AND SHOULD MAKE FINDINGS CONSISTENT WITH GOVERNMENT CODE §16429.5

As set forth in CalCCA's Motion, the Commission lacks jurisdiction to address the questions in Issue 7 to the extent they pertain to CAPP, and thus CalCCA urges the Commission to grant CalCCA's motion to remove Issue 7 in the context of CAPP from the scope of this proceeding. If the Commission nevertheless asserts its jurisdiction (by either denying CalCCA's Motion or failing to

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31 *Id.* §16429.5(g) (emphasis added).

32 *Id.* §16429.5(f)(4).

33 *See CalCCA Motion*, at 10-11 (discussing the specific jurisdiction delegated by the Legislature to CSD to administer the CAPP program, and the statutory resolution by AB 135 and Government Code section 16429.5 of the allocation of CAPP arrearage relief funding to CCA customers (Issue 7.b. in the Scoping Memo), and the Waterfall in the context of CAPP (Issue 7.c in the Scoping Memo)).

act) and proceeds to consider in this proceeding Issue 7 as it relates to CAPP, the Commission must make findings consistent with Government Code §16429.5, including the following:

- ➢ The methodologies currently employed by the IOUs for allocation of partial payments between IOUs and CCAs of past due balances conforms to the requirements of Government Code §16429.5**(f)(4)**, which addresses only partial payments.
- ➢ Consistent with Government Code §16429**(g)**, each IOU must implement a methodology for allocation of any CAPP funds received by the IOU and both the IOU and the CCA must receive their proportionate share of funds on behalf of their customers; each load-serving entity's (LSE's) "proportionate" share is calculated by dividing an LSE's total CAPP-eligible balances in the "bucket" to which CSD disburses the funds by the combined CAPP-eligible balances in that bucket for both LSEs.

CalCCA further urges the Commission under these circumstances to modify the current schedule to issue a final decision on this narrow issue not later than September 30, 2021. This will ensure that the Commission's actions do not act as a barrier to swift processing of IOU applications and customer relief.

## V. ISSUE 7 SHOULD BE RETAINED IN THIS PROCEEDING FOR CONSIDERATION IN THE CONTEXT OF OTHER RELIEF PROGRAMS OR CONSIDERED IN R.18-07-005

The questions raised in Issue 7 – allocation of relief funds and allocation of past due payments – may be relevant in contexts other than CAPP. Specifically, allocation of COVID relief to CCA customers in arrears through state or federal programs other than CAPP may need to be considered by the Commission. In addition, while AB 135 extended the suspension of the Waterfall through the administration of the CAPP program (therefore at least until March of 2022), a more appropriate venue to consider a permanent decision regarding the Waterfall would be in the current Disconnections rulemaking, R.18-07-005. Thus, while either removing Issue 7 from the scope of this proceeding for purposes of CAPP or making a ruling on Issue 7 for Purposes of CAPP, the Commission should include the Issue 7 questions issues in one or both of these related proceedings to address other potential relief programs.

## VI. CONCLUSION

CalCCA appreciates the opportunity to submit this brief and requests adoption of the recommendations proposed herein.

Respectfully submitted,

Evelyn Kahl

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

August 27, 2021

# Submit comment on Issue paper

Initiative: Clarifications to reliability must-run designation process

**1. Provide a summary of your organization's comments on the Clarifications to Reliability Must-Run (RMR) Designation Process issue paper:**

California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Clarifications to RMR Designation Process Issue Paper (Issue Paper). Given the tight supply conditions facing California in the coming years, and the resulting system and local RMR designations that have occurred in recent months, it is prudent for the California Independent System Operator (CAISO) to commence this initiative to evaluate how RMR costs and credits are allocated when a resource meets both a local and system reliability need.

The CAISO should allocate RMR costs in a manner that reflects benefits received. As such, the CAISO must revisit the process for allocating costs when a resource is needed for both local and system reliability. The costs for local RMR are allocated to all load-serving entities (LSEs) serving load in the transmission access charge (TAC) area in which the local area is located. The costs for system RMR are allocated to all LSEs in all TAC areas since the resource serves needs across the entire system. When an RMR meets both a system and local need, it is not appropriate to allocate costs only to LSEs in the local area because all customers will benefit from the reliability to the system afforded by the RMR. Therefore, the CAISO should modify the process for designating RMRs by assessing if the resource meets both local and system reliability needs and allocate costs to all customers that benefit from the RMR designation.

**2. Provide your organization's comments on the primary reliability need topic, as described in section 2.1:**

The Issue Paper outlines five issues to consider when choosing a primary reliability need for which to make an RMR designation when two reliability needs exist, including:

1. Historical considerations of local reliability needs as primary;
2. Infrastructure investment incentives;
3. LSEs benefitting from the RMR;
4. The local resource adequacy (RA) premium; and
5. The need to convert existing RMR contracts.

As the CAISO notes, since start-up the CAISO only designated resources for local reliability needs and it currently considers it the primary reliability need any time it is binding. However, given the current state of California supply conditions, the CAISO issued RMR designations for the Midway Sunset and Kingsburg plants for system reliability needs.[1] Additionally, the CAISO designated a local RMR for the Agnews plant, recognizing it was possible the resource could also have been needed

[1]http://www.caiso.com/Documents/Apr9-2021-InformationalReport-ProposedNewRegulatoryMustRun-RMR-Kingsburg-ER19-1641.pdf

from a system perspective.[2] Because local resources inherently meet system needs, when there is a system reliability need for an RMR in addition to a local need, costs and credits should be allocated on a system wide basis commensurate to those who receive the benefits. While this differs from the CAISO's historical practice of designating resources for local reliability needs only, statewide supply conditions have begun to necessitate RMRs for both system and local needs. As such, the CAISO should modify its allocation methodology so that when an RMR is meeting both reliability needs, costs and credits are allocated to all customers receiving the benefit of the resource.

The CAISO states the responsible utility has an incentive to invest in infrastructure to address local issues that drive local designations, and this incentive is lost if the system need is considered primary. While this may have been true with a small number of LSEs, the number of LSEs in each TAC area has increased substantially in recent years. This diminishes the incentives for the utility to invest in infrastructure to address local reliability needs and prevent the need for CAISO to rely on RMR because the costs of RMRs are spread among a larger quantity of LSEs. CalCCA agrees investments should be made when needed to alleviate local reliability concerns without relying on RMRs, either through transmission or generation alternatives. However, these projects will likely need to be identified in the Transmission Planning Process given the incentives for a utility to invest in infrastructure upgrades to avoid RMRs are not as strong as they once were. Given infrastructure investment incentives from RMRs alone are likely not strong enough to result in infrastructure upgrades to relieve the local reliability need, they should not drive cost allocation. Instead, cost allocation should be driven by all reliability benefits provided by the RMR.

The CAISO suggests that if a system wide need is considered the primary need, then all current local RMR contracts will have to be designated and converted to system wide RMR contracts (including cost and RA credit allocations) for as long as the system reliability need exists. This concern should not prevent the CAISO from making modifications to RMR allocations in a manner that reflects all benefits received. Upon Federal Energy Regulatory Commission (FERC) approval of modifications to RMR allocations, the CAISO should begin using this allocation process for all new RMRs designated for a system and local benefit. Existing RMRs should be converted during the process for extending RMRs that results in CAISO Board approval each October. The CAISO has indicated this initiative cannot conclude by October of this year. Therefore, the process for converting existing RMRs would be done in October 2022.

**3. Provide your organization's comments on the proposed initiative schedule and EIM Governing Body role, as described in section 4:**

CalCCA supports this initiative's Energy Imbalance Market (EIM) Governing Body classification.

**4. Additional comments on the Clarifications to RMR Designation Process issue paper:**

No additional comments at this time.

[2] http://www.caiso.com/Documents/PresentationPotentialReliabilityMustRunDesignationAgnewsPowerPlantMay182021.pdf at 7.

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

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

**OPENING COMMENTS OF MARIN CLEAN ENERGY TO ADDRESS GOVERNOR NEWSOM'S JULY 30, 2021 PROCLAMATION**

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August 31, 2021

## Table of Contents

## I. INTRODUCTION

Marin Clean Energy ("MCE")[1] appreciates the opportunity to submit the below opening comments in response to the Administrative Law Judge's August 6, 2021 *Email Ruling Requesting Comments/Proposals to Address Governor's Proclamation of July 30, 2021* ("August 6 Ruling").[2] The August 6 Ruling invites parties to submit proposals for specific actions that the California Public Utilities Commission ("Commission") can take to "expedite or accelerate clean energy project development as soon as possible, particularly for the Summers of 2022 and 2023," consistent with Governor Newsom's Proclamation of a State of Emergency, issued on Friday, July 30, 2021 ("Emergency Proclamation").

The Emergency Proclamation responds to the effects of climate change and notes that "California currently faces an additional projected energy supply shortage of up to 3,500 megawatts during afternoon-evening 'net-peak' period of high power demand on days where there are extreme weather conditions."[3] The Emergency Proclamation notes that the California Independent System Operator ("CAISO") sought to procure additional resources but that sufficient resources were not available to make up for the projected shortfall for summer 2021. Therefore, it is necessary "to take immediate action to reduce the strain on the energy infrastructure," to minimize reductions in emissions, and to protect the health and safety of Californians.[4] The

[1] MCE, California's first CCA, is a not-for-profit public agency that began service in 2010 with the goals of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs. MCE is a load-serving entity ("LSE") serving approximately 1,200 MW peak load, providing electricity generation services to more than 1.1 million people in 364 communities across Marin, Contra Costa, Napa and Solano counties.
[2] Administrative Law Judge's Email Ruling Requesting Comments/Proposals to Address Governor's Proclamation of July 30, 2021 (hereinafter "August 6 Ruling").
[3] Proclamation of a State of Emergency, July 31, 2021, *accessible at*: https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.
[4] *Id*.

Emergency Proclamation thus directs all state agencies "to act immediately to achieve energy stability."

Through the August 6 Ruling, the Commission seeks proposals for specific actions that the Commission can take under the Energy Efficiency ("EE") Rulemaking R.13-11-005 *by the end of 2021* to address the Emergency Proclamation and the need to reduce strain on the grid.[5] As further explained below, MCE is already running an innovative demand flexibility program, the *Peak FLEXmarket,* currently funded through MCE's generation revenues, that is well-equipped to meet the Commission's goals in MCE's service area. MCE thus proposes that the Commission authorize ratepayer funding, drawn from MCE's remaining budget in unrequested funds,[6] to scale *Peak FLEXmarket* and to achieve expanded customer access that will deliver increased peak load reduction and grid benefits during the summer of 2022 and 2023.

For clarity and transparency, MCE notes that it is including this same funding request in Opening Testimony that MCE plans to file on September 1, 2021 in Rulemaking ("R.") 20-11-003. 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.

Furthermore, MCE recommends that the Commission make modest but impactful modifications to the cost-effectiveness requirements of EE programs to augment and accelerate the implementation of programs under MCE's existing EE portfolio. Specifically, the Commission should take the following actions in furtherance of the goals of the Emergency Proclamation:

[5] August 6 Ruling at 8-9.
[6] As further described in Section II.A.v, *infra*, MCE defines "unrequested funds" as the differences between the funds approved in MCE's Business Plan and the total budget that MCE has requested to date in its annual budget advice letters ("ABAL"), which amount currently approximates $11.9 million.

- the Commission should move to the Program Administrator Cost ("PAC") test for performance-based, meter-based EE programs that pay on Total System Benefits ("TSB"); and
- the Commission should expedite the update of the Cost Effectiveness Tool ("CET") to allow for custom load shapes for reporting savings claims.

## II. RELEVANT BACKGROUND

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 ("Code") Section 381.1(a)-(d) since 2013.[7] The Commission originally restricted MCE's EE programs to serving gaps in Investor Owned Utility ("IOU") programs and hard-to-reach markets.[8] On January 17, 2017, MCE filed a Business Plan with the Commission that requested authorization to expand MCE's EE portfolio to include additional sectors (including residential, commercial, industrial, agricultural) and programmatic offerings, such as workforce education and training ("WET") programs.[9] On June 5, 2018, the Commission approved MCE's Business Plan in D.18-05-041.[10] MCE currently administers programs in multifamily, single-family, commercial, agriculture and industrial sectors, as well as a program focused on WET. Additionally, MCE administers the Low-Income Families and Tenants ("LIFT") program under the umbrella of the state's Energy Savings Assistance ("ESA") program.

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[7] To date, MCE is the only community choice aggregator ("CCA") to have requested energy efficiency funding under Code Section 381.1(a)-(d).
[8] *See* Decision ("D.") 12-11-015, *Decision Approving 2013-2014 Energy Efficiency Programs and Budgets*, at 45-46, issued Nov. 15, 2012.
[9] *See* Application ("A.") of Marin Clean Energy for Approval of its Energy Efficiency Business Plan in A.17-01-017, filed January 17, 2017.
[10] *See* D.18-05-041, *Decision Addressing EE Business* Plans, Ordering Paragraph 33 at 189, issued June 5, 2018.

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. MCE's Commercial Energy Efficiency Market 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 energy efficiency. It is a population-level normalized metered energy consumption ("NMEC") program,[11] which leverages the CalTRACK methods and is further supported by a comparison group analyses to strengthen confidence in measured savings. MCE works with Recurve,[12] an industry leader in meter-based measurement, to implement the Commercial Energy Efficiency Market, which runs off of Recurve's Demand FLEXmarket platform.

The Commercial Energy Efficiency Market program launched in early 2021 with a ~$1M budget and expanded quickly to a ~$5M annual budget, largely due to the ease of participation and strong interest from aggregators.[13] Since the Commercial Energy Efficiency Market compensates aggregators based on the avoided cost value of their projects, weighted heavily towards peak hours, much of the early interest came from aggregators that are active in the demand response ("DR") arena. However, to date, MCE has not been able to pay for the demand flexibility they could deliver with EE funds. This is because demand flexibility impacts (peak period savings) and resources (*e.g.*, energy storage systems ("ESS"), controls systems, behavioral demand response) do not fit within EE framing, which measures project value based on equipment useful life,

[11] *See* NMEC Rulebook, Version 2.0 at 5, 10-13 (January 7, 2020) ("NMEC Rulebook").
[12] Recurve is an industry leader in meter-based demand flexibility. 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/.)
[13] 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 MCE to participate in the program.

measure load shapes, customer cost considerations, and other elements that are outside of the valuation of demand flexibility as a resource.

Thus, to ensure that the value of these demand flexibility resources was not overlooked, MCE launched the *Peak FLEXmarket* off of the same program platform. 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.

## III. COMMENTS

### A. The Commission Should Authorize the Use of Ratepayer Funds for the *Peak FLEXMarket* to Leverage and Quickly Deploy Demand Flexibility Measures that Directly Address the Needs of the Emergency Proclamation.

MCE's *Peak FLEXmarket* is designed to incent behaviors and solutions that directly address the needs espoused in the Emergency Proclamation; namely, reducing peak demand and improving grid reliability. Due to its innovative methods for evaluating load impacts, the *Peak FLEXmarket* is able to measure and pay for both daily load shifting (or energy efficiency) *and* peak-load reduction. It is also uniquely positioned to integrate with MCE's existing EE programs and has already received enrollments from MCE EE partners.

Additionally, the *Peak FLEXmarket* has already launched and attracted a diverse network of aggregators. 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. The *Peak FLEXmarket* program presents a prudent ratepayer investment opportunity that could respond quickly—as required by the Emergency Proclamation—to reduce strain on California's energy infrastructure and improve grid reliability.[14]

While MCE proactively self-funded the initial *Peak FLEXmarket*, 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 grow to the scale it is designed for, it will require access to additional funding. Accordingly, MCE respectfully submits the following proposal, in accordance with the August 6 Ruling.

### *i. Description of programmatic approach or value proposition*

<u>Programmatic approach</u>

MCE's *Peak FLEXmarket* is a market-driven resource program that assigns an hourly value to measured, behind-the-meter ("BTM") load reduction impacts. The *Peak FLEXmarket* is supported by a robust measurement and verification ("M&V") plan, and a program platform that 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. Whereas MCE's Commercial Energy Efficiency Market assigns an hourly value based on 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).

One of the primary attributes of a price-signal driven program is that it enables the *Peak FLEXmarket* to remain technology agnostic: it is 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;

[14] *See* Emergency Proclamation at ¶ 13.

- 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;
- The program design is simple and attractive to demand flexibility providers, (including those more traditionally aligned with EE programs) and lends itself to seamless integration with existing EE programs.

Customers and/or aggregators can participate under the *Peak FLEXmarket* with a behavioral DR offering, a device-enabled strategy (*e.g.*, batteries, smart thermostats, or electric vehicle chargers), or any other solution that generates verifiable results. 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 behind-the-meter solutions to work together in a coordinated way.

*Program Enrollment*

Aggregators enroll by signing a "Flexibility Purchase Agreement," which outlines the key terms of participation and MCE requirements. 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[15] shifting out of the peak hours between June and October.

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[15] The net load is calculated to account for any load increase.

*Current Payment/Incentive Structure*

The *Peak FLEXmarket* works to incent load shifting during summer peak periods in two ways: (1) daily load shifting (*i.e.*, "Flex Savings")[16] and (2) demand response (*i.e.*, "Resiliency Events").

In its current form, which is subject to iteration and improvement as the program scales, Flex Savings are paid at $150/MWh (a rate that is currently aligned to approximate average summer peak avoided cost values). Payments for Resiliency Events are currently pegged to CAISO day-ahead market prices. MCE developed this payment structure to quickly launch the program and gauge interest in its initial stage; however, to scale the program in a manner consistent with the Emergency Proclamation—and to remain competitive with other programmatic offerings—MCE proposes to increase its incentive levels as described further below, in Section II.A.v.

Resiliency Events are currently called at the discretion of MCE – although have generally aligned with CAISO Flex Alerts – and are intended to incentivize demand reduction during periods of high grid congestion, power shortages, or high prices. Resiliency Events are usually triggered when CAISO day-ahead ("DA") Market prices exceed $200/MWh for more than 2 hours, or when one hour exceeds $300/MWh. In the peak summer months in 2021, aggregators are paid at the DA Market price for Resiliency Event energy impacts, ranging from $200-800/MWh. Participants are notified no less than 24 hours in advance of a Resiliency Event.

There are a few different reasons for providing a Flex Savings payment in addition to the payments for Resiliency Events:

[16] Flex Savings are defined as daily load shifted out of the 4-9 PM timeframe on summer weekdays.

- Ensure that load shifting out of the peak hours becomes common practice, consistent and achievable, rather than leaning on DR purely as an emergency lever;
- Numerous DR solutions could be leveraged every day – not just during DR events – but traditional DR baseline measure methods and incentive structures result in a disincentive to regularly reduce demand. This dilemma is resolved through the *Peak FLEXmarket*'s methods;
- There are carbon, grid resiliency, and cost benefits that can be realized if load-shifting is more commonly practiced;
- Daily load shifting aligns with customer benefits, where peak demand may impact time-of-use ("TOU") or peak demand surcharges, and customer potential for cost avoidance may even outweigh the benefits of standalone DR.

*Value Proposition*

One of the biggest challenges in addressing the Governor's Emergency Proclamation is to identify programmatic approaches that can be designed, developed, launched, *and have a meaningful impact* by summer 2022. Historically, it has taken 2-3 years, at minimum, to develop new ratepayer-funded energy programs, and this is true for both the EE realm, as well as other DER-related programs.[17] Much of this is driven by the fact that the Commission has traditionally directed the large IOUs to implement customer programs. If the Commission wants to implement innovative programs quickly that deliver both grid and customer benefits, there needs to be a paradigm shift in how customer programs are developed in the future. CCAs, which are now

[17] Examples of this include the roll-out of the 3rd party EE programs under the IOU's current rolling portfolio cycle, the roll-out of the IOU's Disadvantaged Communities Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs under the NEM proceeding, among others.

providing electricity service to a significant percentage of Californians,[18] are the ideal partners for the Commission in developing innovative programs on a fast-track timeline. CCAs have proven themselves as nimble, quick and adaptive in designing, developing and launching new customer programs.

The *Peak FLEXmarket* is a prime example of the potential in CCA-administered programs. Motivated by the Commission's call to all load-serving entities ("LSEs") to achieve significant customer-sided load reductions during the summer of 2021 to ensure grid reliability, MCE designed, developed and launched the *Peak FLEXmarket* within three months. And, within three months of launching the program, and is already tracking hundreds of meters under aggregated portfolios. While data on load reductions achieved is still pending (due to the recent launch of the program), MCE is confident that a future iteration of the program in 2022 will yield impactful results.

Another key innovation and benefit of the *Peak FLEXmarket* is that it represents a new way of thinking about the value of DR and demand flexibility. It removes the disincentive for aggregators and customers to reduce peak demand on a daily basis. In other DR programs, doing so would reduce the baseline from which demand response is often measured ("10 in 10" baseline load profile[19]), thereby reducing the customer's expected load reduction credit.

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[18] *See California CCAs Amass 6,000 MW in Long-Term Contracts with New-Build Clean Energy Resources* (Nov. 11, 2020) ("As of 2020, CCAs serve over 50 gigawatt-hours (GWh) of load, representing 28% of the load in the service areas of California's three main investor-owned utilities (Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison). Based on planned CCA launched over the next two years, CalCCA forecasts CCAs will serve 36% of IOU load in 2022."), accessible at https://cal-cca.org/california-ccas-amass-6000-mw-in-long-term-contracts-with-new-build-clean-energy-resources/.

[19] The "10 in 10" baseline methodology takes the average customer load from the 10 previous days and applies a same-day load adjustment factor to account for weather. (*See*, *infra*, n.23, (comparing DR baseline methodologies).)

*Measurement and Verification*

Recurve's methods deployed in the *Peak FLEXmarket* are open source and publicly available. Energy impacts will be determined through the CalTRACK 2.0[20] methods, paired with a comparison group adjustment.[21] The methods are distinct for the full participants and resiliency event-only participants.

Within the *Peak FLEXmarket*, determining demand flexibility impacts begins with a thorough assessment of a customer's baseline. First, up to a full year of baseline data is collected to develop a counterfactual that is normalized for weather. Additionally, the comparison group adjustment generates further confidence in measured impacts through a "difference of differences" calculation. As a result, the *Peak FLEXmarket* can credit both Flex Savings and the energy impacts generated during Resiliency Events, or Resiliency Events alone for customers who do not engage in load shifting. In summary, the *Peak FLEXmarket*'s methods demonstrate a substantial improvement over commonly used DR baseline methodologies, which undervalue DR impacts and thus discourage deeper engagement from providers and customers.[22] These methods also

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

[21] A comparison group is a group constructed after participants have been enrolled in a program, wherein the purpose is to compare energy consumption changes from program participants against non-participants with otherwise similar usage characteristics. Comparison group analysis can help determine net savings by accounting for externally driven changes or trends that affect energy usage across all customers or all customers within a segment. (NMEC Rulebook at 21.)

[22] *See* U.S. Department of Energy and National Renewable Energy Laboratory "Study of Demand Response during the California August 2020 blackouts" (December 2020), pp. 6-7, (explaining the drawbacks of prevailing DR baseline methodologies and noting that "current baseline methods understate performance on the days when the grid has the greatest need for demand response, resulting in reduced incentive to support the grid in future events. More accurate methods for measurement and verification will help companies…bring more flexible demand from local distributed energy resources to help balance the grid."), *accessible at* https://assets.website-files.com/5cb0a177570549b5f11b9550/6050a2a48c39eb09319c9382_Quantifying%20The%20OhmConnect%20Virtual%20Power%20Plant%20During%20the%20California%20Blackouts%20(1).pdf.

provide MCE with a pathway to reliably and verifiably integrate demand flexibility into its EE programs, including, but not limited to, the Commercial Energy Efficiency Market.

Equally promising, the *Peak FLEXmarket* has engaged aggregators who are new to demand response programs and MCE program partners who have traditionally been aligned with EE project development. These partners have now been presented with a value proposition for demand flexibility, which can be incorporated into new project specifications and incentive structures now, and prior to June 1, 2022. Integrating energy efficiency is not only sensible from a load management standpoint; it is also critical to unlocking value for customers, and helping to carry the cost of smart, dispatchable technologies.

***ii. Specific measures or technologies***

The *Peak FLEXmarket* is technology and measure agnostic by design. It is capable of integrating a wide range of demand management strategies and clean distributed energy resources ("DERs"), including ESS, smart thermostats, managed electric vehicle charging, building/equipment controls or behavioral demand response.

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, thereby minimizing performance risk to the program and optimizing the deployment of demand flexibility solutions.

***iii. Building type***

The *Peak FLEXmarket* is agnostic to building type.

***iv. Customer market segment***

The *Peak FLEXmarket* is also agnostic to customer market segment, 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.[23] Customers with highly unique load shapes (*e.g.,* large industrial customers) are not an optimal fit for the *Peak FLEXmarket* at present. 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.

***v. Incremental funding needs, if any***

MCE relied on its own generation revenues to self-fund and quickly launch the *Peak FLEXmarket*; however, to grow the market and expand upon the program's initial success, MCE must be permitted access to ratepayer funds for the program's continuation and expansion. MCE forecasts that the *Peak FLEXmarket* can be scaled to accommodate 15 MW of enrolled capacity in 2022 and 30 MW of enrolled capacity by 2023 if sufficient funding is put in place. MCE proposes that the Commission approve $11,559,375 in program funding for program years ("PYs") 2022 and 2023 to effectuate this growth and the goals espoused in the August 6 Ruling (see a more detailed budget proposal below).

This budget projection is largely driven by incentive payments for Flex Savings and Resiliency Events and the need to maintain a rate that is competitive with other program offerings, particularly those that benefit from ratepayer funding. MCE believes it is appropriate to continue offering a payment rate of $150/MWh for measured daily load shifting or shedding. The primary justification for paying for Flex Savings at $150/MWh is that it roughly aligns with the average avoided cost value of savings generated during the summer months' peak hours.

[23] 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.

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. It is important for the value of grid resiliency and demand reduction, as a resource, to remain consistent (as much as practicable, and with possible exceptions for LSE-controlled loads or DR programs with equity goals). Without a consistent value for peak demand reduction, it is foreseeable 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 reliability and other policy goals.

Moreover, the vast majority of the below-proposed program budget would only be *paid on a performance basis*, using some of the most advanced measurement and verification standards available.

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

| Year | 2022 | 2023 |
|---|---|---|
| Load Shifting Incentives | $1,282,500 | $2,565,000 |
| Resiliency Event Incentives | $1,800,000 | $3,600,000.00 |
| **Incentive Budget** | **$3,082,500** | **$6,165,000** |
| **Implementation, ME&O, Evaluation, Administration** | **$770,625** | **$1,541,250** |
| **Total Program Budget** | **$3,853,125** | **$7,706,250** |

MCE calculates the budget for "Load Shifting Incentives" assuming a Flex Savings rate of $150/MWh for 11.25MW of daily load shift between June 1 and October 31, 2022 and 22.5MW of daily load shift between June 1 and October 31, 2023. MCE calculates the budget for Resiliency Event incentives assuming an incentive rate of $2,000/MWh for up to 60 hours annually for 15MW of capacity in 2022 and 30MW of capacity in 2023. MCE notes that an incentive rate for Resiliency Events of $2000/MWh is currently used for illustrative purposes only. MCE recommends that the final incentive rate for Resiliency Events paid under the *Peak FLEXmarket* be aligned with the incentive rates provided under other DR programs authorized in the ongoing discussions under Rulemaking R.20-11-003.

MCE notes that it submits this funding request for the *Peak FLEXmarket* for PYs 2022 and 2023, as outlined above, in addition to the budget that MCE will request for its EE programs under the upcoming Budget Advice Letter for PYs 2022 and 2023. MCE proposes that *Peak FLEXmarket* funding derive from any unrequested EE funds that have accumulated in the current rolling portfolio cycle. MCE defines "unrequested funds" as the differences between the funds approved in MCE's Business Plan,[24] and the total budget that MCE has requested to date in its annual budget advice letters ("ABALs").[25] At present, MCE has approximately $11.9 million available in unrequested funds.

MCE developed the *Peak FLEXmarket* as a means of increasing grid reliability and of delivering customer benefits while eliminating unintentional negative market barriers that often present when combining energy efficiency and demand flexibility goals. MCE's efforts—and successes—in this regard, should not be limited (or threatened) by the funding opportunities that

[24] *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.

[25] 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 Hence, these funds remain available for use by MCE.

are available to other entities (*i.e.*, IOUs) but restricted from MCE. It is therefore crucial that the Commission maintain a level playing field and grant MCE access to ratepayer funds for the *Peak FLEXmarket*. Such funding will deliver additional benefits to the grid and customers in 2022 and 2023, while also ensuring that MCE's programs remain cost competitive with other IOU-administered DR programs.

#### *vi. Estimated energy savings and/or peak demand savings during the 4-9pm time period*

MCE expects the *Peak FLEXmarket* to achieve 15 MW of peak demand savings during the 4-9 PM time period between June 1 and October 31, 2022 and 30 MW of peak demand savings during the 4-9 PM time period by the summer months of 2023. MCE notes that energy impacts 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.

#### *vii. Whether the program/approach can be implemented by June 1, 2022 or June 1, 2023 (or both), with specific needs for each time period*

MCE has already proven it is capable of rapidly developing and growing the *Peak FLEXmarket*. MCE launched the *Peak FLEXmarket* in the summer of 2021 within record time, and in the first three months of program operation, the *Peak FLEXmarket* enrolled seven aggregators, and is actively engaging ten more who are interested in participating. To date, approximately 1,465 MCE customer sites have been evaluated for data sufficiency and program eligibility, with 1,207 eligible for both Flex Savings and the Resiliency Events, and 95 are eligible exclusively for Resiliency Events.

As an already up-and-running program, the *Peak FLEXmarket* is a unique opportunity for the Commission to achieve meaningful demand reductions by June 2022. Any new program proposals made in response to this Ruling, if conceptual or specific, will have to undergo a long program design, development and launch process that will likely take 12 months at a minimum. The *Peak FLEXmarket*, on the other hand, is the most expedient means to deliver grid resiliency measures in the timeline requested in the Emergency Proclamation, i.e., by summer 2022. Indeed, to achieve meaningful impact by summer 2022, programs need to be designed, developed and up and running by January 1 to begin the customer acquisition process. It is highly unlikely that any program that is not launched yet can meet this ambitious timeline.

#### ***viii. A demonstration that the program or project is incremental to and not captured by existing programs or existing processes***

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.

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

#### ***ix. Modifications to existing Commission decisions or rules, or other detailed actions that the Commission would need to take to bring the proposal to fruition***

MCE is not aware of any specific Commission decisions or rules that must be modified to grant MCE access to EE "unrequested funds" for the *Peak FLEXmarket*. If program funding were authorized as requested herein, MCE suggests filing a revised program Implementation Plan ("IP") with the Commission, outlining additional program details. This IP would follow the stakeholder engagement process as described in D.15-10-028.[26]

### B. The Commission Should Modify Certain Rules to Augment or Accelerate EE Programs under MCE's Existing Portfolio.

MCE proposes below a few modest modifications to existing EE rules and requirements for meter-based programs to accelerate delivery of the programs under MCE's existing EE portfolio. Specifically, the Commission should take the following actions in furtherance of the goals of the Emergency Proclamation: (1) the Commission should modify cost effectiveness ("CE") requirements for performance-based, meter-based EE programs that pay on Total System Benefits ("TSB"); and (2) the Commission should expedite the update of the Cost Effectiveness Tool ("CET") to allow for custom load shapes for reporting savings claims.

#### *i. Move to the PAC test for performance-based, meter-based EE Programs that pay on TSB.*

MCE recommends that the Commission take the incremental step of moving to the PAC test immediately for certain pay-for-performance program models. More specifically, the PAC should be applied to programs that measure and pay for performance based on net benefits, such as MCE's Commercial Energy Efficiency Market Program.

The Commercial Energy Efficiency Market pays aggregators for benefits delivered and is a true resource program—*i.e.*, it is not prescriptive in outlining customer solutions or what customers should be paid in incentives. The TRC test includes all customer costs in the cost-benefit equation, but does not account for all customer benefits. The arbitrary inclusion of customer cost in a program like MCE's Commercial Energy Efficiency Market limits the valuation of the net benefits that can be used as a basis for payment to aggregators. In doing so, it also limits

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[26] *See* D.15-10-028, *Decision Re Energy Efficiency Goals for 2016 and Beyond and Energy Efficiency Rolling Portfolio Mechanics*, at 63.

the program value of serving as a stimulus for investment in energy efficiency within MCE's service area.

The transactions involving program funding are separate from the consideration of customer benefit and customer costs – which is further highlighted by the fact that program payments are grounded in total system benefits, not customer savings. The program funding is leveraged as an incentive for aggregators to complete more projects with the goal of delivering benefits – load shaped energy efficiency – and the only relevant costs are resource acquisition costs.

As the Commission recently indicated, costs tests should be used to set the minimum expected value of energy investments, rather than establishing a cap, particularly where additional EE investments are in furtherance of the public interest.[27] The Emergency Proclamation clearly found that increasing grid reliability is in furtherance of the public benefit.[28] Accordingly, MCE strongly urges the Commission to allow for use of the PAC for performance-based, meter-based EE programs, such as the Commercial Energy Efficiency Market Program under the August 6 Ruling.

***ii. The Commission Should Expedite the Update of the CET to Allow for Custom Load Shapes.***

The TSB metric relies on the Avoided Cost Calculator ("ACC") and the CET to calculate the total benefits a measure provides to the electric and natural gas system.[29] This process to determine TSB performs well for deemed measures where PAs can input a measure's annual energy savings with its associated deemed hourly load shape in the CET. However, this process

[27] *See* D.21-05-031, *Assessment of EE Potential and Goals and Modification of Portfolio Approval and Oversight Process*, at 22, issued May 26, 2021.
[28] *See, e.g.*, Emergency Proclamation at ¶ 7.
[29] *See* Total System Benefit Technical Guidance at 2, *available at* https://pda.energydataweb.com/api/view/2530/DRAFT%20TSB%20Tech%20Guidance%20081621.pdf.

incorrectly evaluates TSB for meter-based programs because PAs are forced to combine meter-based savings with deemed hourly load shapes in the CET.

To better evaluate and value TSB from meter-based programs, PAs should be able to utilize custom load shapes in the CET to demonstrate actual, real-world savings and grid conditions, which may be greater than those that would be valued through the use of a modeled load shape on a deemed measure basis.

## IV. CONCLUSION

In sum, MCE recommends that the Commission take the following actions to rapidly achieve the grid reliability and public health goals identified by the Emergency Proclamation and the August 6 Ruling:

i. Authorize MCE's request for $11,559,375M in funding for the *Peak FLEXmarket* from MCE's unrequested EE funds under the current EE portfolio cycle;

ii. Move to the PAC test for performance-based, meter-based EE programs that pay on TSB;

iii. Expedite the Commission's update of the CET tool to allow for custom-load shapes for reporting savings claims.

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

Respectfully submitted,

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