NOVEMBER FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PCIA PREPAYMENT PROPOSALS DISCUSSED AT NOVEMBER 4, 2019 WORKING GROUP

Irene K. Moosen
Director, Regulatory Affairs
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
Regulatory@cal-cca.org

Evelyn Kahl
Ann C. Springgate
Buchalter, A Professional Corporation
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
ekahl@buchalter.com

Counsel to the
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

November 14, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PCIA PREPAYMENT PROPOSALS DISCUSSED AT NOVEMBER 4, 2019 WORKING GROUP

Pursuant to Rule 1.9 of the Commission's Rules of Practice and Procedure, and the *Phase 2 Scoping Memo and Ruling of Assigned Commissioner* filed February 1, 2019, California Community Choice Association (CalCCA)[1] submits the following comments.

I. SUMMARY

CalCCA supports the Commission's determination that prepayment of PCIA obligations is a valuable method to protect customers from rate shock and support a stable market. To facilitate the effective use of prepayment, the Commission should 1) reject attempts to introduce true-ups and other barriers, and 2) allow prepaying LSEs flexibility in the number of years and amount of load they prepay.

II. PRINCIPLES

As discussed in previous comments, CalCCA submits the following principles for a successful prepayment framework: [2]

---

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

[2] CalCCA Comments on SDG&E/AReM/DACC Suggested Prepayment Approach at April 4, 2019 working group.

- Transparent: clear delineation of resources included, inputs, and assumptions.
- Binding: once a pre-payment is made there will be no true-ups/re-evaluations/re-negotiations—this obviates the central benefit of prepayment: certainty.
- Consistent: prepayment amount should be calculated in uniform manner for all customers (DA, CCA, and even bundled) and include all net costs and benefits.
- Unbiased: calculated net present value should not be skewed to favor one customer class over another.

III. SDG&E/AReM/DACC CONSENSUS APPROACH TO DEVELOPING PREPAYMENT "STARTING POINT"

CalCCA supports the consensus approach of SDG&E/AReM/DACC (Co-Chairs) to developing a starting point for prepayment negotiations. This approach for developing a prepayment amount is a hybrid between one set by regulators in a Commission-approved docket (the approach recently used in Nevada) and one bilaterally negotiated between investor-owned utilities (IOUs) and departing/departed load serving entities (LSEs) (recently used in Washington State). The Co-Chairs propose establishing a "starting point" based on the net-present-value of future net liabilities, calculated as:

> Total Costs – Brown Power, Renewable Energy Credits (REC), and Resource Adequacy (RA) values as calculated in Final Adders. The Co-Chairs suggest that, following this "starting point", both LSEs independently develop their suggested prepayment price and then negotiate to determine a mutually-agreeable final price.

However, the fatal flaw in this approach is that the IOU has zero incentive to transact, and, in fact, has actively advocated against the use of any prepayments in the PCIA proceeding. The for-profit utilities are in an enviable position. If market values decline, they charge a higher PCIA. But if market values increase sufficiently such that PCIA goes negative (e.g., results in a refund to departed customers) the

IOUs' advocate to wipe the slate clean. A Proposed Decision issued on November 1, 2019 would eliminate this negative PCIA in PG&E territory for pre-2009 vintage customers.[3]

As AREM/DACC noted in its testimony, each IOU already has in its New Municipal Departing Load tariff the option to have the PCIA and other departing load obligations paid as a negotiated lump sum.[4] Yet none have occurred since the early 2000's. If two parties are expected to negotiate to a mutually-agreeable end, but only one of them has an interest in transacting, there is little chance of an equitable solution. CalCCA remains concerned that while the analytical framework for developing a starting point based on known costs and forecasted values is sound, there remains no carrot or stick to incent the IOUs to act.

IV. RESPONSE TO SDG&E'S ADDITIONAL CHARGE

SDG&E proposes that IOU exposure to market uncertainty be mitigated by imposing a charge on departing customers *in addition* to the calculated prepayment amount. This extra charge, dubbed a Non-Prepayer Protection Reserve (NPPR), would be added to the prepayment cost derived by mutually agreed-upon inputs used to develop the starting point discussed above. SDG&E argues that this is 1) necessary to ensure indifference, and 2) not a true-up.

Requiring departing customers to pay more than the estimated net-present-value of future liabilities would systematically *prevent* indifference. Any calculated prepayment amount should be based on the best information available. This would allow both customer classes to be indifferent at the time of the transaction. The NPPR is an attempt to manipulate the calculation to benefit one group of customers at the expense of another.

---

3 *Proposed Decision Adopting Settlement Agreement Resolving Negative Indifference Amount* (Proposed Decision), Application (A.) 16-04-018, Nov. 1, 2019, available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M319/K117/319117122.PDF.

4 Ex. AReM/DACC AD-1 at section IV.C, 27-28.

SDG&E argues that the NPPR is not a true-up, as these are expressly forbidden by Decision (D.) 18-10-019.[5] Instead, they compare it to an insurance product that may be refunded in the future. This metaphor breaks down, though, as insurance is a product that is either required or desired by the buyer. The NPPR is not required for departing load customers, nor is it desired. This is akin to requiring all new home buyers in Marin to purchase hurricane insurance and then refunding the cost of the policy in the future if hurricane damages were less than expected. There is some merit in SDG&E's argument, however, as true-ups offset both positive and negative values. In other words, they flow in either direction and have the potential to benefit either group of customers. That being said, the NPPR cannot benefit departing customers.

If indifference is what is sought by applying an NPPR, then it must be available to all classes of customers on an equal basis. That would result in both the remaining and departing customers paying an equal, additional charge which would go into an escrow account. Then, at the end of the prepayment period, any under- or over-collection would be refunded to the corresponding customer class. However, this is the definition of a true-up. Thus we are in a scenario where the NPPR—by definition—violates the indifference principle. However, correcting this by treating all customer classes equally and allowing benefits to flow in either direction results in a true-up; which is specifically prohibited in D. 18-10-019.

Finally, the amount of the additional NPPR is undefined. If adopted, IOUs could pursue an NPPR which is 200% of the net-present value of future PCIA obligations. This would effectively triple the prepayment amount, a figure which could easily be in the billions of dollars. We must remember

---

[5] D.18-10-019, Ordering Paragraph #11 at 163, Oct. 19, 2018, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M232/K687/232687030.PDF.

that the IOUs have opposed even allowing prepayment as an option to be considered. The Decision adopting new PCIA methodologies reasoned that:

> [T]he record evidence cited by the Joint Utilities does not support their assertion that requiring them to accept a prepayment of a customer's long-term cost responsibility would shift substantial risks to remaining bundled service customers. Furthermore, AReM/DACC effectively rebutted the Joint Utilities' expressed concerns about forecast-related market risk, volumetric risk, and regulatory risk.[6]

V. SLICE OF LOAD TOOL

Both IOU and Direct Access (DA) providers enjoy a level of certainty that CCAs do not. The former through rate recovery guaranteed by the Commission, and the latter through a known and fixed load. CCAs have neither. If a CCA forecasted and pre-paid based on a 95% participation rate, and instead saw that participation rate decline to 80% over the coming decades, they would have pre-paid an obligation for a customer load they no longer serve. This risk is not solely driven by participation rates; CCAs see load declines due to effective DER programs, wildfires, etc. Additionally, requiring prepayments for 100% of the current load would in turn require CCAs to obtain financing for the full 100%, which may be difficult and/or costly to secure.

Ratemaking for the slice of load concept could be done akin to what is being proposed in PCIA Working Group #3 addressing IOU portfolio management. In that context, CalCCA, Commercial Energy, and SCE are evaluating how PCIA would operate for LSEs that take an allocation of attributes (e.g., RECs and RA). The most practical solution being discussed in Working Group #3 is to keep PCIA constant for all LSEs, and charge LSEs that take the allocation of attributes an additional fee. This same concept could be applied to LSEs prepaying a slice of load. Departed customer PCIA would remain the same as it would under the annual construct we have today. Then, any difference in the fixed prepayment amount in a given year would be credited or debited to the LSE.

---

6 *Id*. at 91.

It bears noting that the IOUs have raised the risk of the opposite scenario—unexpected load increases of departed LSEs—as a risk to bundled customers. However, load growth in a region in excess of what IOUs initially forecasted and procured for does not pose a risk to bundled customers. PCIA is not intended to function as an on-going account to which IOUs can charge all above-market costs. It is intended to compensate utilities for unavoidable sunk costs made on behalf of a customer the IOU no longer serves. Imagine PG&E was procuring for a forecasted load of 2,500 GWh in Sonoma County. Then, in 2014, Sonoma Clean Power launches and that 2,500 GWh departs. If in the next five years the load increases to 2,600 GWh, that additional 100 GWh is new load not already procured for by PG&E. It will not impact PG&E's remaining customers and is the sole responsibility of Sonoma Clean Power.

VI. CONCLUSION

CalCCA appreciates the opportunity to provide these comments in support of a prepayment methodology that is transparent, binding, consistent, and applied equitably to customers of all LSE types.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl

Counsel to
the California Community Choice Association

November 14, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Marin Clean Energy for Approval of its Multifamily Whole Building Program under the Energy Savings Assistance Program 2021-2026	Application 19-11-___ (Filed November 4, 2019)

APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF ITS MULTIFAMILY WHOLE BUILDING PROGRAM UNDER THE ENERGY SAVINGS ASSISTANCE PROGRAM 2021-2026

Jana Kopyciok-Lande
Senior Policy Analyst
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6044
Facsimile: (415) 459-8095
E-Mail: jkopyciok-lande@mceCleanEnergy.org

November 4, 2019

TABLE OF CONTENTS

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

Application of Marin Clean Energy for Approval of its Multifamily Whole Building Program under the Energy Savings Assistance Program 2021-2026	Application 19-11-___ (Filed November 4, 2019)

APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF ITS MULTIFAMILY WHOLE BUILDING PROGRAM UNDER THE ENERGY SAVINGS ASSISTANCE PROGRAM 2021-2026

I. INTRODUCTION

Marin Clean Energy ("MCE") respectfully submits this application for approval of MCE's Multifamily Whole Building ("MFWB") Program under the Energy Savings Assistance ("ESA") program for Program Years ("PY") 2021-2026 ("Application"). ESA is a statutorily established program that provides home weatherization services to qualifying low-income customers. This Application is being submitted in compliance with Decision ("D.") 16-11-022, which approved MCE's Low-Income Families and Tenants ("LIFT") Pilot Program ("LIFT Pilot") to provide energy efficiency ("EE") upgrades to both in-unit and common areas of low-income multifamily dwellings, including the installation of heat pumps.[1]

D.16-11-002 also directed MCE to "use the Application process if it elects to extend the LIFT pilot on a more permanent basis in [this] next program cycle."[2] Included with this Application is the *Testimony of MCE Regarding its Application for Approval of its Multifamily Whole Building Program Under the Energy Savings Assistance Program 2021-2026* ("MCE Testimony"). The MCE Testimony follows the California Public Utilities Commission's

[1] *Decision on Large Investor-Owned Utilities' California Alternate Rates for Energy (CARE) and Energy Savings Assistance (ESA) Program Applications* ("D.16-11-022"), filed on November 21, 2016, at Ordering Paragraph ("OP") 147.
[2] D.16-11-022 at pp. 390-391.

("Commission" or "CPUC") directive in its *Decision Issuing Guidance to Investor-Owned Utilities for California Alternate Rates for Energy/Energy Savings Assistance Program Applications for 2021-2026 and Denying Petition for Modification* ("Guidance Decision").[3] Because MCE is only seeking to become a Program Administrator ("PA") for the MFWB Program, the MCE Testimony focuses mainly on the specific requirements described in the MFWB section of the Guidance Decision.[4] However, the MCE Testimony also includes information from other sections of the Guidance Decision where relevant and helpful.

II. SUMMARY OF APPLICATION AND REQUESTS

MCE proposes to build upon the successes and lessons learned from the LIFT Pilot and expand its reach with a new LIFT 2.0 Program, developed under the umbrella of the ESA MFWB program. LIFT 2.0 specifically addresses the Commission's mandate for deeper savings and innovative program designs for the low-income multifamily sector.[5] LIFT 2.0 was developed based on community feedback and incorporates tangible recommendations and lessons learned from MCE's LIFT Pilot. While the details of program design and delivery will be developed through the third-party solicitation process as envisioned by the Guidance Decision,[6] MCE is proposing several "cornerstones" of program delivery in this Application. These activities are specifically designed to address the obstacles observed in the low-income multifamily EE space and thereby will accelerate program adoption.

Specifically, MCE requests Commission approval of MCE's Application for its LIFT 2.0 Program, including the activities and proposed budgets as highlighted below, as soon as practical.

[3] D.19-06-022 filed on June 28, 2019. The Decision entails three documents: (1) the Decision; (2) Attachment A: Guidance Document for the ESA and CARE Program Budget Applications for PYs 2021-2026, and (3) Attachment B: Excel templates.
[4] D.19-06-022, Attachment A at pp. 20-23.
[5] D.19-06-022 at p. 9.
[6] *Id.*

1. A third-party designed and implemented MFWB program as directed by D.19-06-022,[7] and MCE's proposed solicitation process and timeline;
2. A total budget of $10,603,955 over six years (2021 – 2026) to achieve the following goals:
    - Average annual per unit energy savings of 474 kilowatt-hours ("kWh"), 0.13 kilowatts ("kW") and 59.67 therms, not including fuel substitution measures;
    - Target whole building and in-unit measures at 80 properties and approximately 4,400 units; and
    - Increase the average overall reported tenant satisfaction with health, comfort and safety metrics when comparing pre-treatment to post-treatment results;
3. MCE's program delivery cornerstones, which are based on the obstacles observed in the low-income multifamily EE space, including:
    - Adjust the income eligibility threshold to 60% area median income ("AMI") to account for regional cost of living and to allow for more streamlined income verification processes;
    - Layer program offerings through MCE's Single Point of Contact ("SPOC") model to streamline customer experiences;
    - Treat naturally occurring affordable housing ("NOAH") properties while maintaining affordability;
    - Join with local governments and other community organizations as trusted messengers to reach vulnerable customer groups;
    - Offer innovative EE measures to be determined with third-party implementers,

[7] *Id.*

including fuel switching components such as heat pumps, as well as those that can ease the adoption of time of use ("TOU") rates such as smart thermostats and grid-connected water heaters;

  - Provide flexibility to multifamily building owners in the choice of contractors and installed equipment;

4. MCE's high-level plan for carrying out program evaluation, measurement and verification ("EM&V"); and
5. Continued local MCE administration of the LIFT 2.0 Program.

Support for each of the above requests is detailed in the MCE Testimony and the sections below.

III. BACKGROUND

MCE was established in 2010 as the first operating Community Choice Aggregator ("CCA") in California and serves 34 communities across Marin County, Contra Costa County, Napa County, and Solano County.

MCE has developed and administered general market (i.e., non-income qualified) EE programs since 2012.[8] Many of MCE's general market EE programs utilize third-party solicitations to request innovative program designs, take advantage of EE market expertise, and drive innovation in MCE's EE portfolio. MCE currently administers residential multifamily EE programs for non-income qualified customers as part of its approved ten-year Business Plan.[9] MCE's Multifamily Energy Savings ("MFES") program provides multifamily buildings with complimentary home energy assessments, no-cost technical assistance, low-cost loans and

[8] *Decision Enabling Community Choice Aggregators to Administer Energy Efficiency Programs* ("D.14-01-033"), filed January 23, 2014.
[9] *Decision Addressing Energy Efficiency Business Plans* ("D.18-05-041"), filed on June 5, 2018.

complimentary energy and water direct install measures for tenant units. MFES has been promoting EE in multifamily settings since 2012 and has a strong history of serving income-qualified properties.

Due to the large percentage of low-income properties participating in MCE's general market MFES program, MCE proposed the LIFT Pilot program under the investor-owned utilities ("IOUs") ESA program and budget applications in 2015.[10] The Commission approved MCE to administer its LIFT Pilot for two years in November 2016 in D.16-11-022.[11] In September 2019, MCE received approval to extended the LIFT Pilot timeline through the current ESA program cycle.[12]

Since its launch in October 2017, the LIFT Pilot has met or exceeded the expectations established at the onset of the Pilot.[13] Most notably, the LIFT Pilot has resulted in

- enrollment of 1,163 units comprising 21 properties;
- 130 heat pump reservations with 57 installations;
- high success in reaching hidden communities;
- 82% satisfaction report from tenants; and
- successful cross-promotion and enrollment in other available programs through MCE's SPOC model.[14]

In the Decision approving the LIFT Pilot, the Commission stated, "MCE shall use the

[10] A.14-11-007, *Testimony of Marin Clean Energy Regarding a Proposed Low-Income Energy Efficiency Pilot Program for the Program Years 2015-2017*, filed on April 27, 2015.
[11] D.16-11-022 at Ordering Paragraph ("OP") 190.
[12] MCE Advice Letter 38-E, *Request for Timeline Only Extension of Marin Clean Energy's Low-Income Families and Tenants Pilot*, filed on September 11, 2019.
[13] MCE established metrics to track the status of the LIFT Pilot in MCE AL 23-E and 23-E-A, filed on April 6, 2017 and July 20, 2017 respectively.
[14] MCE submitted an interim report on the LIFT Pilot program in April of 2019, providing additional details on the status, key successes and lessons learned from Pilot implementation to date.

Application process if it elects to extend the LIFT Pilot on a more permanent basis in the next program cycle."[15] This is the relevant Application in which MCE is electing to extend the LIFT Pilot.

IV. LEGAL AND POLICY FRAMEWORK

The ESA Program is mandated by Public Utilities Code Section 2790(a), which reflects a legislative "policy of reducing energy-related hardships facing low-income households."[16] Public Utilities Code Sections 739.1 and 739.2 establish the California Alternate Rates for Energy ("CARE") program. The Commission authorized the low-income rate assistance programs in D.89-07-062 and D.89-09-044. Assembly Bill ("AB") 1890 was passed in 1996, establishing the framework for deregulating the California energy industry. Public Utilities Code Section 382, which was part of that bill, addresses funding for the ESA and CARE programs.

The California legislature provided CCAs a right to administer EE programs in Public Utilities Code Section 381.1. CCAs also have an obligation to provide EE programs because they are load-serving entities ("LSEs") and because EE is at the top of the loading order for generation resources under California state policy.[17] MCE must therefore be able to fully leverage EE as a generation resource. The Commission recognized the need for CCAs to administer EE programming in approving MCE's last EE Business Plan, even where there was the potential for overlapping programs with IOUs.[18]

Accordingly, MCE must have equal access to ESA Program funding in order to effectively

---

[15] D.16-11-022 at p. 387.
[16] Cal. Pub. Util. Code § 2790(a).
[17] Cal. Pub. Util. Code § 454.5(b)(9)(C) indicates: "[t]he electrical corporation shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible." See also State of California Energy Action Plan I, 2003 at p. 4 (defining a loading order with energy efficiency as the primary resource); and the Energy Efficiency Policy Manual at p. 1 (noting energy efficiency is a procurement resource and first in the loading order).
[18] *See,* D.18-05-041 at p. 111.

provide comprehensive EE programming to its low-income customers on par with the IOUs regardless of potential overlap. The Commission further recognized the value and legitimacy of CCA administered ESA programming in approving MCE's LIFT Pilot and directing MCE to come back for additional funding via this next ESA program cycle.[19]

Additional statewide laws and policies further support Commission approval of MCE's Application to expand EE offerings in the low-income multifamily sector. First, Public Utilities Code Section 382(e) states "[t]he commission shall, by not later than December 31, 2020, ensure that all eligible low-income electricity and gas customers are given the opportunity to participate in LIEE ["low income energy efficiency"] programs, including customers occupying apartments or similar multiunit residential structures." Second, Senate Bill ("SB") 350 requires the state to reduce greenhouse gas ("GHG") emissions by 40% below 1990 levels.[20] The bill also requires the California Energy Commission ("CEC") and the CPUC to create a plan by 2023, to achieve statewide *doubling* of EE savings and demand reductions by 2030.[21] Third, AB 3232 further requires the CPUC, CEC, California Air Resources Board ("CARB") and the California Independent System Operator ("CAISO") to specifically assess the potential for the State to reduce GHG emissions associated with the supply of energy to both the commercial and residential building stock by at least 40% below 1990 emissions levels by 2030.[22] MCE's LIFT 2.0 Program will assist the Commission and the State to achieve these ambitious and worthy EE, building de-carbonization, low-income participation, and GHG reduction goals.

LIFT 2.0's targeted offerings also advance the CPUC's Environmental and Social Justice

[19] D.16-11-022 at p. 387.
[20] Cal. Pub. Util. Code § 454.52(a)(1)(A).
[21] Cal. Pub. Res. Code § 25310(c)(1).
[22] Cal. Pub. Res. Code § 25403 (a).

("ESJ") Action Plan, which emphasizes the need to advance equity in programs and policies for ESJ Communities.[23] LIFT 2.0 is well positioned to advance these ESJ goals by offering to serve the traditionally underserved multifamily low-income building sector.

In summary, MCE's LIFT 2.0 Program is offered pursuant to existing ESA legislation, a CCA's right to administer EE programming, a CCA's obligation to utilize EE in serving load, and furthers numerous State policy objectives such as GHG reduction, building electrification and the ESJ Action Plan. As such, the Commission has the authority to grant MCE the right to administer LIFT 2.0 as a permanent ESA MFWB program.

V. MCE'S LIFT 2.0 PROGRAM DISCUSSION

LIFT 2.0 will incorporate the successful aspects of the LIFT Pilot while expanding the offering to specifically address remaining obstacles in the income-qualified multifamily space. MCE outlines its main requests for Commission approval and LIFT 2.0 Program design proposals below. Additional detail can be found in the MCE Testimony.

A. The Commission should approve LIFT 2.0 as a third-party designed and implemented program as envisioned by the Guidance Decision

LIFT 2.0 complies with the Commission's Guidance Decision and its direction to select a third-party entity to design and implement the MFWB program.[24] Third-party implementation is an effective program delivery model utilized frequently in ratepayer-funded EE programs, which acknowledges that different vendors bring unique experience in specific target markets or technology areas. While not explicitly required to do so, MCE utilizes the third-party solicitation

[23] Environmental and Social Justice Action Plan, Version 1.0, February 2019, *available at* https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Commissioners/Martha_Guzman_Aceves/Env%20and%20Social%20Justice%20ActionPlan_%202019-02-21.docx.pdf at p.6.
[24] D.19-06-022 at p.9.

process in its general EE programming because MCE understands the value in utilizing private market expertise for program design and implementation.[25] MCE further believes that utilization of third-party implementers is consistent with MCE's obligation to pursue cost-effective EE programs to meet its customer's procurement needs.[26]

By utilizing third-party implementers in the LIFT 2.0 Program, MCE, as the PA, will be able to effectively focus on independent program oversight, budget management, evaluation, EM&V, and reporting of program impacts to the Commission. On the other hand, MCE's program implementers are well positioned to deliver projects and generate program impacts, grow a network of qualified contractors or installers, lead outreach to stakeholders, and review targeted technologies and their specifications. Allowing third-party implementers to focus on these activities will maximize cost effectiveness. For these reasons, the Commission should approve MCE's MFWB program as a third-party designed and implemented program.

MCE elaborates on its proposed solicitation processes and timeline in the MCE Testimony and proposes the following specific solicitation schedule:

[25] *See*, *Decision Providing Guidance for Initial Energy Efficiency Rolling Portfolio Business Plan Filings* ("D.16-08-019"), filed on August 25, 2016, at pp. 69 – 70 (upholding third party requirements for utilities).

[26] A.17-01-013, *Final Reply Comments of Marin Clean Energy on Energy Efficiency Business Plans* ("MCE Final Reply Comments"), filed on October 13, 2017, at p. 5 (*citing, Decision Enabling Community Choice Aggregators to Administer Energy Efficiency Programs* ("D.14-01-033"), filed on January 23, 2014, OP 3, at p. 50 (Applying IOU cost- effectiveness standards to CCAs); and *Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Programs and Budgets* ("D.14-10-046"), filed on October 24, 2014, at pp. 109-110 (Setting a TRC ratio of 1.25 for IOUs and CCAs)).

Task	Time after Program Approval
Issue Solicitation	4 weeks
Vendor Selection	3 months
Executed Contracts	5 months
Stakeholder Workshop on Program Design	6 months
Launch Program	7 months

B. The Commission should approve MCE's budgets and goals for LIFT 2.0 and make the appropriate funding available for the program cycle 2021-2026

The proposed program budget for LIFT 2.0 is $10,603,955 over six years (2021 – 2026). Annual budget details and the excel budget template as specified in the Guidance Decision are provided in MCE's Testimony.

This funding will allow MCE to pursue the following goals:

- **Energy savings targets:**[27] annual, per unit savings of 474 kWh, 0.13kW and 59.67 therms, not including fuel substitution measures;[28]
- **Household targets:** target whole building and in-unit measures at 80 properties and approximately 4,400 tenant units;
- **Health, safety and comfort improvements:** increase the average overall self-reported tenant satisfaction with health, comfort and safety metrics when comparing pre-treatment results to post-treatment results.

MCE requests that the Commission approve its proposed LIFT 2.0 budgets and direct

[27] Because the measure list for LIFT 2.0 will be finalized in partnership with the third-party implementer, these targets are subject to change.
[28] While savings are averaged on a per unit basis, they include any savings from whole building or common area measures, averaged by the number of units in a particular property. Per unit average savings are more comparable than per property average savings due to variations in property size.

PG&E to transfer MCE's annualized LIFT 2.0 Program budget by January 15 of each year, similar to the process adopted in D.14-01-033 and further refined in R.13-11-005 for MCE's administration of general market EE funding.[29]

C. The Commission should approve MCE's proposed program design and delivery strategies, which specifically address obstacles to implementing energy efficiency for income-qualified customers in multifamily buildings and which will accelerate Program adoption

Tenants and property owners of income-qualified multifamily properties face myriad obstacles for accessing and engaging in available EE programs. To accelerate MFWB program adoption, LIFT 2.0's delivery strategies are specifically designed to address the obstacles MCE encountered in servicing income-qualified multifamily properties under the LIFT Pilot.

Further, MCE gathered feedback from various different stakeholder groups on its LIFT 2.0 Program proposal. MCE discussed the proposal with advocacy groups with a longstanding engagement in the IOU's ESA programs, such as Energy Efficiency for All. Furthermore, MCE presented the LIFT 2.0 Program proposal to MCE's Community Power Coalition, a group of diverse advocacy organizations that addresses issues of equity, sustainability, environmental justice and disadvantaged communities ("DACs"). Finally, the LIFT 2.0 Program proposal was presented to and discussed with MCE's board of directors, comprised of elected officials from the local governments that comprise MCE's service area. Through its experience and investigation, MCE has identified the following obstacles to EE program implementation in the income-qualified multifamily space that are being addressed under LIFT 2.0.

[29] D.14-01-033 at pp. 17, 37.

i. LIFT 2.0 addresses customer acquisition barriers

One of the major hurdles of current EE low-income multifamily programs relates to customer acquisition, especially in regards to identifying and enrolling low-income customers in NOAH properties.[30] At the same time, NOAH properties constitute the majority of low-income multifamily buildings and units in MCE's service territory.[31] In D.16-11-022, the Commission recognized the challenge and difficulties of reaching a competitive market sector for privately owned, non-deed restricted, multifamily housing for participation in ESA programs.[32]

Unlike existing ESA Programs administered by the IOUs, which focus primarily on deed-restricted properties,[33] LIFT 2.0 will serve all eligible low-income multifamily properties. NOAH properties are challenging to identify, as these properties are not included in government datasets as low-income housing. However, MCE's network of local government agencies, community organizations, and EE implementers have a long-standing history in working with this customer segment and are knowledgeable about how to best identify and approach them. Granting MCE the authority to administer LIFT 2.0 will further the Commission's objective of identifying NOAH properties for participation in ESA programs.[34] LIFT 2.0 also includes a number of measures to ensure that EE upgrades implemented under the program do not negatively impact affordability in NOAH properties. These measures include requiring landlord, tenants and MCE to sign enforceable affidavits that limit rent increases and evictions, as well as establish additional reporting and monitoring provisions.

---

[30] NOAH includes residential rental properties that maintain low rents without federal subsidy or deed restrictions

[31] Based on TRC Memorandum for PG&E "ESA Multifamily Common Area Non-Deed Restricted Opportunity Analysis– 2018 Annual Report Filing Final Analysis."

[32] D.16-11-022 at p. 180.

[33] PG&E ESA CAM Implementation Plan at p.18. See at https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_3943-G.pdf

[34] *See*, D.16-11-022 at pp. 189-190.

Another customer acquisition barrier is the need to earn the trust of vulnerable and hard-to-reach populations and to address concerns regarding the sharing of personal information (e.g., income verification documentation). In order to address this customer acquisition barrier, MCE will work with local government partners such as city and county housing agencies as marketing, education and outreach ("ME&O") partners to make the first touch with building owners. This collaboration places credible organizations at an early point of engagement, which is a crucial period for gaining customers' trust. MCE is already successfully partnering with local governments on targeted customer outreach. For example, MCE is partnering with the Aging and Adult Services Division of the Marin Health and Human Services to deliver health and safety related measures into properties with large populations of aging and elderly residents. Additionally, MCE has also been working with the Contra Costa County's health program to identify properties with a high incidence of asthma and provide health services and EE upgrades through a single program. MCE proposes to deepen this coordination under LIFT 2.0 and to identify additional specific outreach channels with other local governments.

ii. LIFT 2.0 addresses program eligibility barriers

Once a customer has been identified and approached, the next barrier to overcome are the challenges associated with current ESA Program income eligibility thresholds and processes. To address these challenges, LIFT 2.0 seeks to move beyond the income eligibility threshold of 200% Federal Poverty Guideline ("FPG"), which CARE and ESA presently use. Instead, MCE proposes to use 60% AMI as the income eligibility threshold for LIFT 2.0, thereby aligning the program with other EE and clean energy programs for income qualified customers.

MCE believes that revising the income eligibility threshold for ESA participation is within the Commission's discretion and is appropriate here, where significant barriers exist in reaching vulnerable populations in multifamily buildings in the Bay Area because of the extraordinarily high cost of living. The Commission initially tied the ESA income eligibility threshold (of the then-called "low-income weatherization" or "LIW" program) to the statutorily mandated income threshold for CARE in Resolution E-3254, adopted January 21, 1992.[35] In that Resolution, the Commission adjusted the income limitation for the LIW program (with some exceptions) "to match the CARE program to reduce customer confusion."[36] In Resolution E-3439, adopted on February 23, 1996, the Commission held that all utilities should use the (then) 150% FPG for CARE and LIW programs, but also provided an income eligibility threshold of 80% of *county* median income for "community type or block weatherization programs… in a specifically designated low income area with Commission approval."[37]

Two important conclusions can be drawn form these Resolutions regarding the CPUC's authority to modify ESA eligibility criteria. First, Resolution E-3254 established a link between ESA and CARE eligibility for the express purpose of reducing customer confusion between the two programs. For LIFT 2.0, where MCE will provide SPOC service, customers will be guided through the process of eligibility screening. Further, various other California programs for low-income customers have adopted income eligibility thresholds that are based on AMI, such as the Solar on Multi-family Affordable Housing ("SOMAH") and Self-Generation Incentive Program ("SGIP") Equity programs. Hence, modifying LIFT 2.0 to 60% AMI would not cause customer confusion but would instead ease customer participation by aligning program eligibility requirements. Second, as noted above, the Commission has already exercised its discretion to depart from CARE eligibility thresholds for ESA/LIW programming in adopting certain

[35] *Order Requiring Energy Utilities to Revise Income Limits for the California Alternate Rates for Energy (CARE) and for the Low-Income Weatherization Program* ("Resolution E-3439"), issued February 23, 1996 at p.1 (*citing* Resolution E-3254, adopted January 21, 1992)
[36] Resolution E-3439 at p. 1.
[37] Resolution E-3439 at p. 2.

community specific programs, just as MCE requests the Commission do with its community focused LIFT 2.0 MFWB proposal.

Revising the income eligibility threshold to 60% AMI will allow LIFT 2.0 to serve in need customers that would otherwise be stranded between the existing ESA offerings and general market EE programs. MCE's service territory, which spans four counties, is home to thousands of low-income households who struggle to make ends meet, but many of them are ineligible for the IOU's ESA programs under the current income eligibility criteria.

Furthermore, MCE proposes a series of additional steps to streamline the income eligibility verification process. For example, MCE plans to allow enrollment into LIFT 2.0 without requiring additional income verification for customers enrolled in the SOMAH and SGIP Equity programs, as well as customers enrolled in the CARE rate. MCE will also offer customized assistance through the SPOC to guide customers through the LIFT 2.0 eligibility verification process.

iii. LIFT 2.0 addresses program complexities

Participants in existing EE programs often criticize the complex program requirements and processes that can prevent participation in programs outright. Additionally, many programs are available to tenants and property owners of low-income multifamily properties, which can be confusing to many customers. The LIFT 2.0 Program addresses complexity barriers by leveraging MCE's proven SPOC model, which MCE has used successfully on all of its programs for several years. To navigate program complexities, MCE's SPOC not only guides customers through the program processes, but also provides technical assistance to optimize the measure mix. Furthermore, the SPOC helps property owners and managers leverage other EE, clean energy and transportation program offerings aimed at low-income multi-family buildings.

iv. LIFT 2.0 empowers customers

MCE's experience under the LIFT Pilot has shown that property owners strongly prefer to have the ability to select specific equipment and contractors of their choosing. While this is not a standard procedure under the ESA Program in general, MCE proposes the Commission allow property owners the flexibility to choose both contractors and equipment under LIFT 2.0. This will further empower program participants' self-sufficiency and engagement in the program. Along those same lines, LIFT 2.0 strives to work with property owner's timelines and plan EE upgrades around larger property remodel projects that may be planned or ongoing.

v. LIFT 2.0 addresses the obstacles of heat pump installations

One of the major obstacles to heat pump installation is the high customer cost share after incentives and/or rebates, which may also include ancillary project costs such as upgrades to the electrical panel. Leveraging other funding sources via the SPOC model will help lower this cost barrier.

vi. LIFT 2.0 supports customers in the use of innovative EE technologies and in the transition to TOU rates

MCE will promote innovative EE technologies under LIFT 2.0, including, but not limited to, fuel substitution and residential demand response ("DR") technologies. Fuel substitution measures have the potential to greatly improve resident's health, safety and comfort. DR services present a way for customers to take control over their energy use and add an additional value stream to their property upgrades.

Surveys conducted with LIFT Pilot participants indicated a general lack of knowledge regarding the benefits and operation of heat pumps. To address this, the SPOC will provide in-person consultation and online tutorials to LIFT 2.0 tenants regarding heat pump operation. While engaging with program participants, the SPOC will also educate tenants and property owners on the use and benefits of DR-enabled technologies and the impacts of the impeding transition to TOU rates.

vii. LIFT 2.0 includes workforce education and training

Under the LIFT Pilot, MCE recognized that one of the main challenges to promoting heat pumps is the dearth of qualified installation contractors. To address this issue, LIFT 2.0 will provide a home performance education component targeting the local contractor population. Contractor education will focus on, but is not limited to, increasing the pool of contractors qualified to install heat pumps. This is consistent with MCE's mission "to address climate change by reducing energy related greenhouse gas emissions through renewable energy supply and energy efficiency at stable and competitive rates for customers while providing local economic and workforce benefits."[38]

MCE has thoughtfully and methodically applied lessons learned from its LIFT Pilot to develop a more effective and efficient LIFT 2.0 Program. The Commission should approve MCE's LIFT 2.0 Program because it is consistent with the Commission's stated focus on innovative program designs for the multifamily sector, including a low-income MFWB EE third-party program.[39]

D. The Commission should approve MCE's high-level plan for carrying out EM&V activities

MCE will contract with an independent third-party to perform EM&V and process evaluations and has set aside four percent of total budget for this task. The exact evaluation process for the new round of ESA Programs has yet to be determined. However, MCE presents its high-level plan for carrying out EM&V activities below.

- **EM&V Objective 1: Verify Program Progress towards Key Success Metrics and Enable Real-Time Program Improvement** - MCE will track program performance based

[38] MCE Mission. Available at https://www.mcecleanenergy.org/.
[39] D.19-06-022 at p. 9.

on a set of key success metrics, including measure level and participant data. Data will be collected in real time and analyzed at critical milestones to determine whether program modifications are necessary.

- **EM&V Objective 2: Quantify the Effect of the Revised Eligibility Criteria and the Targeted Outreach Strategies -** MCE will particularly examine the impact of the updated income eligibility requirements and the revisions to the income verification process on program participation.
- **EM&V Objective 3: Develop a List of Key Accomplishments, Best Practices and Lessons Learned -** MCE will develop a list of program design recommendations and challenges through interviews with program participants, implementation staff, and partners.

E. The Commission should authorize MCE to administer its LIFT 2.0 Program as a local program

As noted above, the Commission approved MCE to administer the LIFT Pilot as a locally run program in MCE's service area in 2016 and explicitly directed MCE to use this Application process to extend the LIFT Pilot on a more permanent basis.[40] MCE has proven its success in implementing the LIFT Pilot, and is uniquely positioned to continue the implementation of multifamily low-income EE programs. First, MCE can build upon the lessons learned from the LIFT Pilot to specifically address the remaining obstacles encountered by income-qualified residents in multifamily properties. Second, MCE's small size compared to utility PAs allows MCE to be more nimble, responsive, targeted, and innovative in its approach to programs. Finally,

[40] D.16-11-022 at p. 387.

MCE's local governance structure and connection to its local community allow MCE to incorporate community feedback into the development of its programs, and to leverage local government partner agencies as outreach mechanisms and for program leveraging. Customer outreach strategies, especially those targeting low-income customers, are best implemented on a local level through trusted messengers to overcome mistrust among vulnerable populations.

MCE recognizes that the Guidance Decision recommends that *the IOUs* propose a statewide-administered MFWB program with a single implementer.[41] As an initial matter, MCE believes this direction was not directed at CCAs or other non-IOU implementers. This is evidenced by the Commission's approval of MCE's LIFT Pilot and its invitations to apply for additional funding to extend LIFT.[42] For the reasons discussed above, MCE finds that program implementation for downstream EE programs, especially those dealing with vulnerable populations, is most successful when implemented at the local level. Locally administered programs can target the specific local needs and challenges, as well as using local agencies as outreach partners. The hurdles encountered under the LIFT Pilot discussed above in Section V. C. can best be addressed with a local program that provides tailored customer support utilizing local community contacts.

Further, D.16-08-019 generally expressed a preference for implementing statewide-administered programs for *upstream and midstream programs*, with a focus on market transformation.[43] The commission ruled that "upstream and midstream programs, where partners are manufacturers, retailers, or distributors, <u>but not contractors, installers, or individual customers,</u> as well as market transformation efforts, are appropriate to be handled on a statewide basis."[44]

---

[41] D.19-06-022 at p. 20.
[42] D.16-11-022 at p. 387.
[43] D.16-08-019 at pp. 57-59.
[44] D.16-08-019 at pp. 51-52 and Conclusion of Law ("COL") 50.

Because the ESA MFWB program involves direct and targeted outreach to low-income multifamily building owners, managers and tenants on an individualized basis, they are not midstream or upstream programs.

Because MCE is uniquely positioned to service its customers, the Commission should approve MCE to be the MFWB local administrator for its service area.

VI. STATUTORY AUTHORITY AND COMPLIANCE WITH THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE

A. Statutory and Other Authority – Rule 2.1

MCE is applying to administer its LIFT 2.0 ESA MFWB Program pursuant to Public Utilities Code Section 2790(a), MCE's authority to administer EE programs pursuant to Public Utilities Code Section 381.1(a)-(d), and the Commission's direction in D.16-11-022 that MCE "use the Application process if it elects to extend the LIFT pilot on a more permanent basis in [this] next program cycle."[45]

B. Legal Name of Applicant and Related Information - Rule 2.1(a)

The legal name of the Applicant is Marin Clean Energy. MCE's principal place of business is San Rafael, California. Its address is 1125 Tamalpais Avenue, San Rafael, CA 94901. MCE is a joint powers authority formed under the laws of California.

[45] D.16-11-022 at p. 387.

C. Correspondence and Communications - Rule 2.1(b)

All correspondence and communications regarding this application should be addressed to:

Jana Kopyciok-Lande Senior Policy Analyst Marin Clean Energy 1125 Tamalpais Avenue San Rafael, California, 94901 Telephone: (415) 464-6044 Fax: (415) 459-8095 E-mail: jkopyciok-lande@mcecleanenergy.org	Alice Havenar-Daughton Director of Customer Programs Marin Clean Energy 1125 Tamalpais Avenue San Rafael, California, 94901 Telephone: (415) 464-6030 Fax: (415) 459-8095 E-Mail: ahavenar-daughton@mcecleanenergy.org

D. Categorization – Rule 2.1(c)

MCE proposes that this Application be categorized as a "ratesetting" proceeding pursuant to Rule 7.1(e)(2) of the Commission's Rules of Practice and Procedure because it does not clearly fit into any of the categories as defined by Rules 1.3(a), 1.3(d), and 1.3(e). MCE's Application does not meet the definition of adjudicatory in Rule 1.3(a) because it is neither an enforcement investigation nor a complaint.

MCE's Application does not clearly fit the definition of quasi-legislative under Rule 1.3(d) because it has components specific to MCE. The specific components include the request for funding for MCE's own ESA MFWB program. Since this application contains components other than quasi-legislative, it is not clearly a quasi-legislative proceeding under Rule 1.3(d).

Categorization of this Application as "ratesetting" under Rule 7.1(e)(2) is consistent with how IOU ESA applications are categorized and how the Commission has previously categorized similar EE funding applications.[46]

---

[46] A.17-01-013, *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, filed on April 14, 2017, at p. 14.

E. Need for Hearing - Rule 2.1(c)

MCE has endeavored to provide a sufficient record via the Application materials to obviate the need for evidentiary hearings. MCE does not recommend hearings at this time. If the need for hearings arises, MCE requests that the resulting hearing schedule allow the Commission to render a final decision on this Application with sufficient time to start implementing the Lift 2.0 MFWB Program at the start of the ESA 2021-2026 program cycle.

F. Proposed Schedule – Rule 2.1(c)

MCE concurs with the preliminary schedule provided in the Guidance Decision with a goal for a final decision that allows implementation of ESA programs by 2021:[47]

File Application	October, 2019
Protests/Replies Due	November, 2019
Reply to Protests	December, 2019
Prehearing Statements/Conference	Winter 2020
Scoping Memo	Spring 2020
Discovery	Spring 2020
Intervenor Testimony/Deadline for motion on hearings	Spring 2020
Rebuttal Testimony	Summer 2020
Hearings/workshops & Discovery cut off	Summer 2020
Opening Briefs	Summer 2020
Reply Briefs	Summer 2020
Proposed Decision	TBD
Comments/Reply Comments on PD	TBD
Final Decision	Winter 2020

G. Issues to be Considered – Rule 2.1(c)

MCE requests the Commission approve MCE's Application for a MFWB Program under the ESA 2021-2026 program to enable MCE to continue serving low-income multifamily

[47] D.19-06-022, Attachment A at p. 36.

properties with weatherization, EE, health, safety and comfort upgrades. MCE also requests the Commission take action to address the following issues:

- MCE's proposed LIFT 2.0 third-party designed and implemented MFWB program;
- MCE's proposed LIFT 2.0 total budget of $10,603,955 over six years (2021 – 2026);
- MCE's proposed LIFT 2.0 goals;
- MCE's program delivery strategies as described in its Application, including but not limited to, a 60% AMI income eligibility threshold;
- MCE's high-level plan for EM&V activities; and
- Continued local MCE administration of the LIFT 2.0 Program.

H. Articles of Incorporation - Rule 2.2

MCE is a CCA operating as a joint powers authority ("JPA") organized under California law. MCE commenced operations as a JPA on December 19, 2008. MCE is engaged in the provision of electric generation services under the authority granted in Public Utilities Code Section 366.2 and general market EE programs under the authority granted in Public Utilities Code Section § 381.1. A copy of MCE's current Amended Joint Powers Agreement, executed April 21, 2016 is available on MCE's website.[48]

I. Rule 3.2 (a)-(d) is inapplicable to MCE's Application

The Rule 3.2 requirements do not apply to this Application because MCE does not request authority to increase rates or to implement changes that would result in increased rates. IOU's perform revenue collection for ESA programs and typically provide the materials called for under Rule 3.2 in their ESA applications. As discussed above in Subsection VI.C (Categorization - Rule 2.1(c)), MCE is not in a position of revenue collection for ESA programs. Thus it is inappropriate for MCE to propose specific rate changes related to this Application. The only information called

---

[48] As of the date of this filing, the most recent Joint Powers Agreement is available at https://www.mcecleanenergy.org/wp-content/uploads/2016/06/JPA-Agreement-with-Amendment-10-on-4.21.16-24-Communities.pdf

for under Rule 3.2 that MCE can feasibly provide is not meaningful to a ratesetting decision in the context of ESA programs. Therefore, it is unreasonable to impose the requirements of Rule 3.2 on this Application. This is the approach followed in similar EE program proceedings.[49]

J. Notice and Service of Application

A copy of the Application and the MCE Testimony are being served on Administrative Law Judge MacDonald and on the parties of record in A.14-11-007 et.al.

K. List of Supporting Documents

MCE submits this Application along with its *Testimony of MCE Regarding its Application for Approval of its Multifamily Whole Building Program Under the Energy Savings Assistance Program 2021-2026* and the attachments thereto.

VII. CONCLUSION

MCE respectfully requests the Commission expeditiously approve this Application.

Respectfully submitted,

By: *Jana Kopyciok-Lande*

Jana Kopyciok-Lande
Senior Policy Analyst
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6044
Facsimile: (415) 459-8095
E-Mail: jkopyciok-lande@mceCleanEnergy.org

November 4, 2019

[49] A.17-01-013, Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan, filed on January 17, 2017, at p. 31.

VERIFICATION

I, the undersigned, say:

I am an officer of Marin Clean Energy and am authorized to make this verification on its behalf. The statements in the foregoing *Application of Marin Clean Energy for Approval of its Multifamily Whole Building Program under the Energy Savings Assistance Program 2021-2026* are true of my own knowledge, except as to the matters which are herein stated on information and belief, and as to those matters, I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct. Executed at San Rafael, California this 4th day of November, 2019.

/s/ Dawn Weisz
DAWN WEISZ
Chief Executive Officer

MARIN CLEAN ENERGY

Docket No.: A.19-11-___
Exhibit No.: (MCE-1)
Date: November 4, 2019
Witness: Alice Havenar-Daughton

TESTIMONY OF MARIN CLEAN ENERGY REGARDING ITS APPLICATION FOR APPROVAL OF ITS MULTIFAMILY WHOLE BUILDING PROGRAM UNDER THE ENERGY SAVINGS ASSISTANCE PROGRAM 2021-2026

MCE | My community. My choice.

TABLE OF CONTENTS

TABLE OF FIGURES

CHAPTER 1: INTRODUCTION

Marin Clean Energy ("MCE") is a not-for-profit public agency that began service in 2010 as California's first operating Community Choice Aggregator ("CCA"). MCE is a load-serving entity serving approximately 1,000 MW peak load, providing electricity generation services to more than 1.1 million people in 34 communities across Marin, Contra Costa, Napa and Solano counties.

Both energy efficiency ("EE") and equity issues are a central part of MCE's mission "to address climate change by reducing energy related greenhouse gas emissions through renewable energy supply and energy efficiency at stable and competitive rates for customers while providing local economic and workforce benefits." MCE has been administering general market EE programs since 2013 under the authority granted in California Public Utilities' (PU) Code 381.1.[1] Issues of sustainability, environmental justice and disadvantaged communities ("DACs") have been at the core of MCE's work since its inception. MCE is addressing the challenges that confront historically marginalized communities within MCE's service area through collaboration with local partners, open dialogue with MCE's communities, by sponsoring workforce development trainings, supporting local hiring for local renewable energy projects, and by offering customer programs for solar and energy efficiency upgrades to income-qualified customers, among others.

In November of 2016, California Public Utilities Commission ("CPUC" or "Commission") Decision (D.) 16-11-022 approved MCE's Low-Income Families and Tenants ("LIFT") pilot program ("LIFT Pilot") under the investor-owned utilities' ("IOU") Energy Savings Assistance ("ESA") and California Alternate Rates for Energy ("CARE") Programs and Budget

[1] MCE initially elected to administer EE programs pursuant to California PU Code 381.1(e)-(f) and then became the first CCA to apply to administer EE programs pursuant to PU Code 381.1(a)-(d) in 2013.

Applications.[2] The LIFT Pilot aimed to reduce the energy burden and improve the quality of life of residents in income qualified multifamily properties in MCE's service territory through health, safety and comfort upgrades. In D.16-11-022, the Commission approved the LIFT Pilot as a two-year pilot and established that MCE shall use the Application process if it elects to extend the LIFT Pilot on a more permanent basis in the next ESA program cycle.[3]

MCE is now proposing the Low-Income Families and Tenants 2.0 program ("LIFT 2.0") under the umbrella of the ESA Multifamily Whole Building ("MFWB") program as outlined by the Commission in D. 19-06-022, *Decision Issuing Guidance to Investor-Owned Utilities for California Alternate Rates for Energy/ Energy Savings Assistance Program Application for 2021-2026 and Denying Petition for Modification* ("Guidance Decision").[4] MCE commends the Commission for its focus on deeper energy savings and innovative program design for the ESA multifamily sector in the Guidance Decision[5] and strongly believes that a third-party designed and implemented program can achieve such an outcome. MCE also recommends that the Commission allow MCE to run LIFT 2.0 as a local program, as downstream EE programs are most successful when implemented at the local level, targeting the specific local needs and challenges, as well as using local agencies as outreach partners. Additionally, local implementation of the ESA MFWB program allows for more learning opportunities and for the Commission to be able to compare and contrast which local implementation strategies are successful in accelerating the adoption of EE upgrades at low-income multifamily properties.

---

[2] "Clean copy" of D.16-11-022, *Decision of Large Investor-Owned Utilities' California Alternate Rates for Energy ("CARE") and Energy Savings Assistance ("ESA") Program Applications*, OP 148. The clean copy of D.16-11-022 was published in an Administrative Law Judge's Ruling Providing a Clean Copy of the Modified Red-Lined Version of D.16-11-022 on February 2, 2018.
[3] *Id*, at p.387
[4] D.19-06-022 at p.9 and Attachment A to D.19-06-022 at pp. 20-23
[5] D.19-06-022 at p.9

MCE is uniquely positioned to administer the MFWB program under ESA in its service area and to accelerate the adoption of EE upgrades for income-qualified multifamily properties. First and foremost, MCE can build upon the successes and lessons learned from the LIFT Pilot and expand its reach with the new LIFT 2.0 program to specifically address the remaining obstacles encountered by income qualified residents in multifamily properties when considering energy efficiency, health, safety and comfort upgrades. Second, MCE's small size compared to utility Program Administrators ("PAs") has allowed MCE to be more nimble, responsive, targeted, and innovative in its approach to programs. Third, MCE's local governance structure and connection to its local community has allowed MCE not only to incorporate community feedback into the development of its programs but also to leverage local government partner agencies as outreach mechanisms.

In preparing for this application, MCE developed a deep understanding of the needs of its most vulnerable and disadvantaged customers, as well as the programmatic challenges of low-income programs, through extensive public and stakeholder input. MCE presented its LIFT 2.0 proposal to MCE's Community Power Coalition, a group of diverse advocacy organizations from across MCE's service area that address issues of equity, sustainability, environmental justice, and disadvantaged communities. The feedback provided was incorporated into this Application. In addition, MCE reached out to ESA program stakeholders and advocacy groups to request input on the obstacles customers are facing who participate in the ESA program and also to request feedback on specific program design ideas. Finally, the LIFT 2.0 proposal was discussed at a MCE Board of Directors meeting, comprised of elected officials from the local governments that comprise MCE's service area.

LIFT 2.0 will incorporate the successful aspects of the LIFT Pilot while expanding the offering to address remaining obstacles in the income qualified multifamily space and to respond to the Commission's mandate for deeper savings and innovative program designs under the MFWB program. The main cornerstones of the LIFT 2.0 program include:

- Adjust income eligibility threshold to 60% Area Median Income ("AMI") to account for regional cost of living realities and to streamline the income verification process;
- Reduce customer confusion and seamlessly layer various program offerings through MCE's applied single point of contact ("SPOC") model;
- Treat naturally occurring affordable housing ("NOAH") properties[6] in addition to deed-restricted properties, while maintaining affordability;
- Work with local governments as trusted messengers on targeted customer outreach to MCE's most vulnerable customer groups including, but not limited to, outreach to residents aging in place and buildings with high incidence of asthma;
- Provide innovative energy efficiency measures with a focus on health, safety and comfort, including heat pumps and Demand Response ("DR") enabled technologies.
- Provide multifamily building owners the opportunity to choose their own contractors and equipment, provided that the work meets program requirements, as well as minimum licensing and liability standards.

[6] NOAH properties are defined as market rate properties that house low income residents but the property itself doesn't have income requirements for its residents. This is different from deed restricted or designated affordable housing properties, in which the property has zoning laws or receives government funding for maintaining a certain number of units for tenants at a lower income.

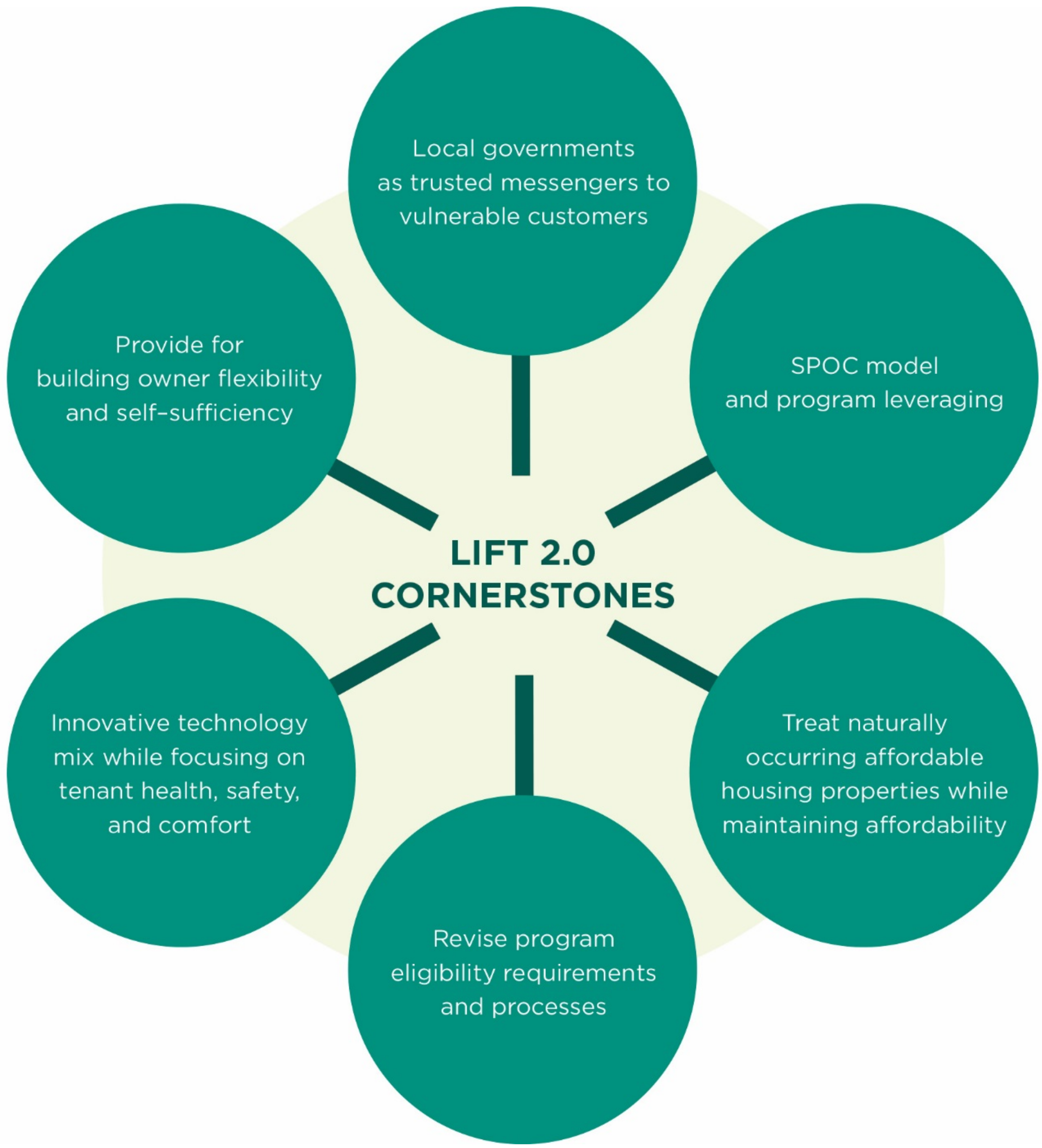


Figure 1 - LIFT 2.0 Cornerstones

With these elements, LIFT 2.0 aims to lower the barriers to participation and accelerate program adoption while delivering cost-effective energy savings and improving the health, safety, and comfort of participating low-income multifamily properties.

Because MCE is only seeking to become a PA for the MFWB program, not the full ESA program, the following testimony specifically addresses the requirements and program design guidelines for the MFWB program under ESA as outlined in Attachment A to the Guidance Decision.[7] However, MCE is also providing additional information to provide more context and background on its Application to become a PA under the MFWB track of the ESA program. In doing so, MCE follows the structure proposed in the Guidance Decision for the IOU's full ESA Applications to the greatest extent possible (irrelevant sections such as Revenue Requirements and Rate Impacts are not being addressed).[8] In summary, the testimony includes the following topics:

- Chapter 1: Introduction
- Chapter 2: ESA Multifamily Whole Building Program Plan and Budget
    - Program Context
    - Proposal Summary
    - Program Goals and Budget
    - Customer Eligibility and Outreach
    - Solicitation Processes and Timeline
    - Program Design and Delivery
    - Program Administration
- Chapter 3: Conclusion
- Chapter 4: Attachments
- Chapter 5: Appendices

[7] D.19-06-022, Attachment A at pp.20-23
[8] *Id* at p.3

CHAPTER 2: ESA MULTIFAMILY WHOLE BUILDING PROGRAM PLAN AND BUDGET

A. PROGRAM CONTEXT

1. MCE's Low-Income Families and Tenants Pilot

MCE's LIFT Pilot provides technical assistance and rebates for energy efficiency measures to income-qualified multifamily property owners and residents. MCE proposed the LIFT Pilot in April 2015 under the IOU's ESA and CARE Programs and Budget Application for the 2015-2017 Program Year (Application A.14-11-007).[9] The LIFT Pilot was approved by the CPUC in November of 2016 in Decision 16-11-002[10] and launched in October 2017.

The LIFT Pilot aims to reduce residents' utility bills, increase energy savings, and improve residents' quality of life through health, safety and comfort upgrades. To be eligible for the LIFT Pilot offering, individual residents of multifamily properties must be at or below the 200% Federal Poverty Guidelines ("FPG") and live in a multifamily building with four or more dwelling units. MCE also aims to identify and serve residents that belong to a hidden community of low-income renters who are not currently benefiting from other low-income energy savings programs.[11]

MCE achieves greater administrative efficiency and reduced burden on property owners or managers by seamlessly blending rebates from MCE's general market EE Multifamily Energy

---

[9] *Testimony of Marin Clean Energy Regarding a Proposed Low-Income Energy Efficiency Pilot Program for the Program Years 2015-2017*, submitted on April 27, 2015 to A.14-11-007
[10] D.16-11-022, OP 147 at p.492
[11] Hidden Communities under the LIFT Pilot are defined as: (1) residents that receive program information in a language other than English; (2) residents that have not previously participated in EE programs; (3) residents that are located outside of Cal Enviro Screen 3.0 designated disadvantaged communities; and (4) units are occupied by extended or multiple families.

Savings ("MFES") program with rebates for income-qualified customers available through the LIFT Pilot. By leveraging both offers, the LIFT Pilot participants get access to:

i. No-cost energy assessments and technical assistance;

ii. Rebates to lower the cost of whole building and common area projects;

iii. No-cost energy and water-savings measures for resident units such as pipe and attic insulation, LED lighting, as well as Energy Star appliances[12]

In addition to general energy efficiency measures, the LIFT Pilot has a fuel substitution component designed to collect data on the performance, energy consumption and bill impacts of electric heat pump water and space heaters in a low-income multifamily setting. Electrification under this Pilot supports cleaner and more efficient energy use while resolving health and safety concerns. The LIFT Pilot funds are used to offer rebates to cover a portion of the costs of purchasing and installing heat pump, conduct onsite evaluation, measurement and verification ("EM&V"), and offer tenant and contractor education on heat pumps.

a. Accomplishments of the LIFT Pilot

MCE has been running the LIFT Pilot since October 2017 and in many aspects, the LIFT Pilot has met or exceeded the expectations established at the onset of the Pilot.[13] Most notably, MCE can report on the following key accomplishments to date:[14]

- **Number of Participating Households and Heat Pump Installations**

---

[12] A list of measures under the LIFT Pilot can be found in Attachment 2

[13] The goals and metrics of the LIFT Pilot were outlined in MCE's Advice Letter 23-E, *Identification of Metrics to Track Marin Clean Energy's Low-Income Families and Tenants Pilot* from April 6, 2017 and 23-E-A, Supplement to the previous Advice Letter, from July 20, 2017.

[14] MCE submitted an interim report on the LIFT Pilot in April of 2019, providing additional details on the status, key successes and lessons learned from Pilot implementation to date.

By the end of August 2019, a total of 1,163 units were participating in the LIFT Pilot, comprising 21 properties.[15] During the same time, 130 heat pumps at five properties entered the rebate reservation step under the Pilot and an additional 57 heat pumps completed installation.

- **Reaching Hidden Communities**

  Results from tenant surveys indicate that MCE is meeting its goal to reach hidden communities as defined under the LIFT Pilot: nearly two-thirds of tenants (65%) indicated that their primary language was Spanish; over 97% of LIFT participants are located outside of Cal Enviro Screen 3.0 designated DACs;[16] and 98% had never participated in an EE program before.

- **Tenant Satisfaction**

  At the time the LIFT Pilot interim report was compiled, 82% of tenants surveyed were very satisfied or somewhat satisfied with the EE measures installed. Ninety-percent of tenants surveyed were very satisfied or somewhat satisfied with the heat pump technology installed. One example leading to high tenant satisfaction is the fact that MCE developed a process in partnership with the CPUC and Pacific Gas & Electric ("PG&E") to automatically update a customer's baseline to "all electric" when heat pump space heaters were installed.

---

[15] A participating unit is defined as a unit that has passed the income qualification process, paid a refundable Good Faith Deposit, and received a site assessment from the program's technical assistance provider.

[16] The LIFT Pilot's goal is to specifically reach customers located outside of DACs as its intention is to reach "hidden communities" and there are several other state-funded programs that specifically focus on customers located in DACs

- **Effective Program Leveraging through the Applied SPOC Model**

MCE serves as the SPOC for property owners and managers under the LIFT Pilot. The SPOC model helps property owners and managers maximize the benefits of a project by providing excellent customer service, bundling demand-side management opportunities, phasing projects to incorporate additional technologies over time, and connecting property owners and managers to available financing programs. The SPOC model also assists in leveraging and streamlining the enrollment process for other programs available to income qualified customers.

Although not a primary objective, the LIFT Pilot has, since launching, become the core program for MCE's Green & Healthy Homes Initiative ("GHHI") Marin Program[17] which further leverages other program funds for health and safety upgrades for qualifying multifamily properties located in Marin County. Once a unit or property located in Marin is qualified for the LIFT Pilot, it automatically qualifies for GHHI. The property receives an expanded comprehensive assessment that identifies home hazards and is then eligible to receive rebates to install health, safety, accessibility and energy efficiency measures in addition to the measures covered under the LIFT Pilot. These added funds make it possible to develop a more comprehensive scope of work for the residents, resulting in a safer, healthier, more comfortable and energy efficient dwelling.

---

[17] GHHI Marin County is a network of local providers coordinating their services to make housing healthier, more accessible, and energy efficient for moderate to low income Marin County residents. Multifamily units can receive up to $2,250 to cover health and safety repairs in the unit, including roof, door and window repair, pest remediation, installation of grab bars and ramps, mold mitigation, installation of energy conservation measures, and heating/cooling systems.

MCE has a proven track record of applying the SPOC model in real-life scenarios. For example, MCE supported Marin Villa, a twelve-unit property located in San Rafael's Canal District. Like its surrounding community, Marin Villa is largely populated by Latino families, many of whom qualify for Section 8 housing vouchers. With guidance from MCE's SPOC, Marin Villa was able to leverage funding from several programs including MCE's general market MFES program, the LIFT Pilot, GHHI, and low-income solar programs (Multifamily Affordable Solar Housing ("MASH") and MCE-funded). The results of the upgrade are shown in the graphic below.

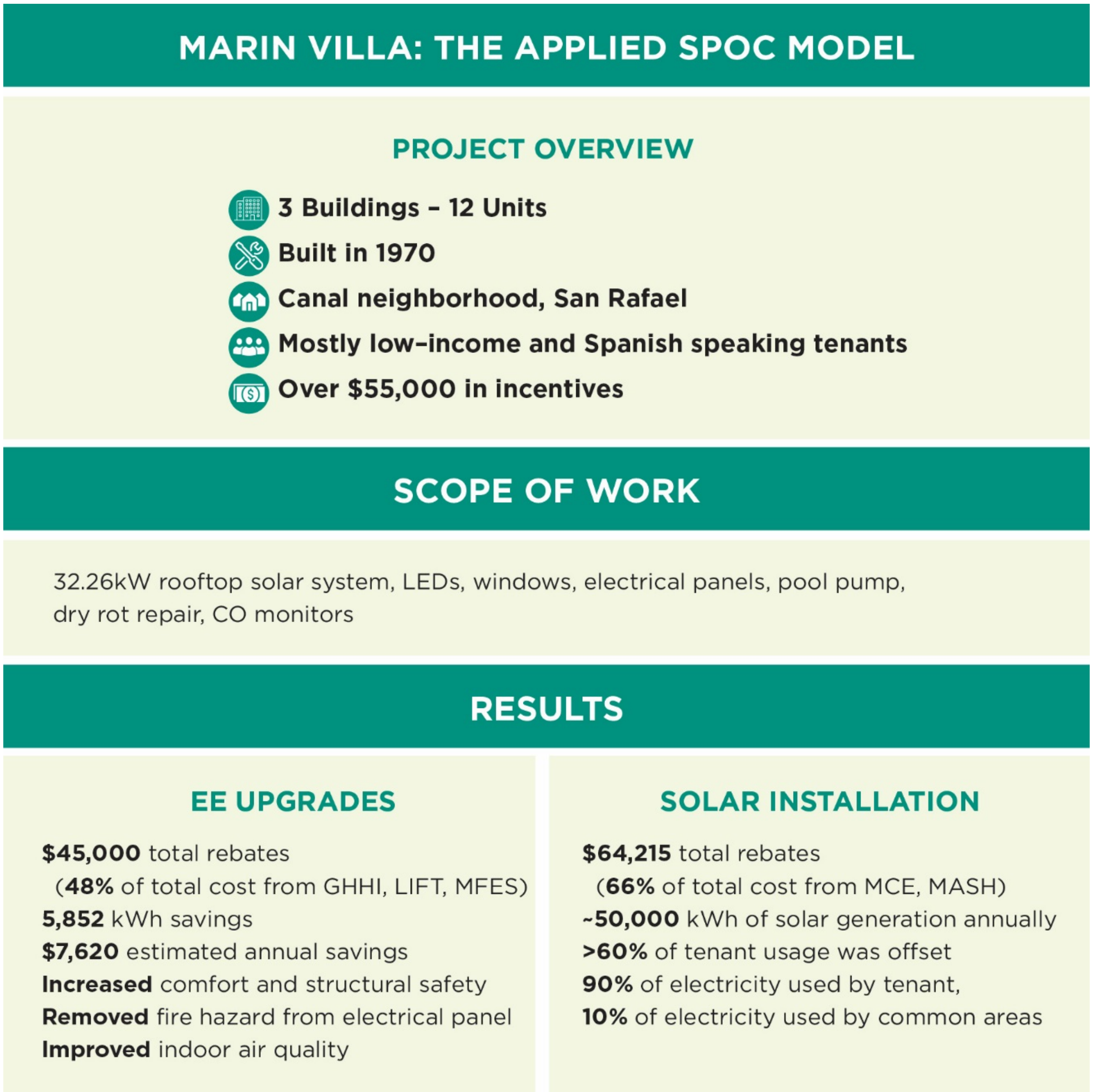


Figure 2 - Marin Villa: The Applied SPOC Model

b. Lessons Learned under the LIFT Pilot

MCE gathered a number of lessons learned from the administration and implementation of the LIFT Pilot:

- **Long Implementation Timelines for Multifamily Properties**

  The average timeline for implementing energy efficiency upgrades at multifamily properties under the LIFT Pilot is approximately 18 months. Multifamily properties can experience delays in finalizing the scope of work for energy efficiency projects for a variety of reasons. Even if they want to participate in the program, they are often subject to following the funding timelines laid out in a tax credit allocation. With smaller properties operating under nonprofits, funding a project can require approval from the board, and timing can also be influenced by grant timelines. These challenges are reflected in the number of units and properties that have completed energy efficiency upgrades and installation of heat pumps under the LIFT Pilot to date. Of the 1163 units participating in the program by August 2019, only 78 had completed energy efficiency upgrades.

- **Outreach to Property Owners and Managers is More Effective than Outreach to Tenants**

  At the beginning of the LIFT Pilot, MCE had planned to partner with community-based organizations in order to reach out to multifamily property residents. The difficulty with this approach was that multifamily properties require property manager or owner consent in order to install upgrades at the property. For this reason, MCE shifted to partnering closely with local governments, community partners, local housing agencies, and affordable housing nonprofits to identify property owners and managers interested in completing energy efficiency upgrade projects, which minimized the need for residents to work with owners to participate in the Pilot.

- **Increased Need for Workforce Development and Training**

  The main barrier MCE experienced to the more widespread installation of heat pumps is the dearth of qualified heat pump installation contractors.

- **Promoting the Non-Energy Benefits of Heat Pumps**

  Another hurdle encountered during the LIFT Pilot is the upfront financial burden for heat pumps. The cost differential between heat pumps and conventional technology underscores the importance of articulating the benefits that users can realize from the installation of heat pumps. While the equipment rebate was successful at reducing this upfront barrier, promoting the non-energy benefits ("NEBs") such as improved air quality, comfort, safety is essential for realizing increased adoption of heat pumps. MCE's approach emphasizes these attributes to the customer while balancing their expectations regarding bill impacts.

c. Continued Challenges under LIFT Pilot

While MCE is proud of the successes of the LIFT Pilot to date, the following challenges continue to persist in implementing the pilot.

- **Income Eligibility Threshold**

  The income eligibility threshold applicable to the LIFT Pilot, which are based on the current eligibility rules of the ESA program and are pegged to the FPG, do not appropriately reflect the income realities of low-income families in the Bay Area. Due to the high cost of living in the region, low-income families are often excluded from participation in the ESA and/or LIFT Pilot program, despite earning well below the AMI for their county.

- **Income Qualification Process**

  In working with NOAH properties, the process for qualifying the property based on income is much simpler when at least 80% of the units meet the program income limit, because the owner affidavit form can be used in these instances. In the cases where fewer than 80% of the units at a property meet the income requirements, an income verification process for each single tenant unit is used. At properties where there is a lack of trust between the property management and the tenants, this can be difficult to accomplish. Often, property owners or managers are under resourced and it is challenging for them to go door-to-door to have residents complete the required form. Although MCE assists with this process, it can be a reason that property owners/ managers disengage from the program.

- **Communication with Individual Tenants and Trust Issues**

  In a multifamily setting, most interaction and communication between the program administrator, implementer and the participating properties occurs through the property owner and/or manager. Individual tenants are often left out of the process leading to communication and trust issues when individual tenant engagement becomes necessary. For example, when the property enlists MCE's help to collect unit-level income verification forms, on occasion, the residents have not been adequately informed about the program by the property management and can be skeptical of participating. Even when residents have been informed about the program, they often feel like the property owner doesn't necessarily have their best interests in mind, and they can be mistrustful and reluctant to participate in the program.

2. Remaining Needs Assessment

MCE has gathered data regarding the remaining need for energy efficiency upgrades in income qualified multifamily properties, both in regards to property numbers in MCE's service territory as well as concerning issues that we will likely require increased attention beyond 2020.

a. Estimate of Affordable Housing Units in MCE's Service Area

MCE has gathered information from publicly available datasets to estimate the number of affordable housing units in the MCE service area. These datasets include a list of properties eligible for Solar on Multi-family Affordable Housing ("SOMAH"), County-sourced data, and data from the online affordable housing aggregator Affordable Housing Online. The table below shows the number of affordable housing properties and units by County/City.

Table 1- Affordable Housing Properties by County

County/City	SOMAH database		County Data		Other Housing Data	
	Properties	Units	Properties	Units	Properties	Units
Marin	48	2251	N/A	3663	69	3237
Contra Costa	133	11922	169	15008	155	14710
Napa	23	1710	57	N/A	25	1588
Unincorporated Solano	0	0	N/A	N/A	0	0
Benicia	1	55	2	155	2	131

b. Time-of-Use Education

As residential accounts across MCE's service area are transitioned to time-of-use ("TOU") rates, there is a need to provide outreach and education to all residential customers, but especially to hard-to-reach low income customers. MCE plans to provide enhanced education to LIFT 2.0 participants on the upcoming transition to TOU rates as this change has the potential to impact customers' utility bills.

c. Monitor Lessons Learned from Other Existing Pilot Programs

The San Joaquin Valley Disadvantaged Communities ("SJVDAC") pilot projects will provide additional learnings for program design elements, primarily around the cost effectiveness of electrification measures, affordability protection, split incentives, and bulk purchasing. As the SJVDAC pilot progresses, preliminary findings in these areas may help inform refinement of LIFT 2.0.

Other pilot programs being developed by the IOUs that may inform LIFT 2.0 are Southern California Edison's ("SCE") Building Electrification Pilot for low-income customers in DACs and PG&E's WatterSavers, which is a behind-the-meter thermal storage pilot that incentivizes customers to switch to heat pump water heaters and operate them off-peak. These pilots will provide information on customer uptake of other electrification measures such as cook tops and load shifting strategies using internet enabled devices.

B. PROPOSAL SUMMARY

MCE's LIFT 2.0 program builds upon the successes and the lessons learned from the LIFT Pilot and further seeks to overcome barriers in existing low-income multifamily EE program offerings. In keeping with the Commission's D.19-06-022, which calls for "a focus on deeper energy savings from measures. . .and innovative program designs for the multifamily sector,"[18] MCE proposes an offering designed to deliver deep energy savings through a set of high-impact measures offered to all eligible, low-income multifamily buildings through a whole building framework. LIFT 2.0 intends to treat 80 properties, including common areas as well as approximately 4,400 units, and achieve an average of 474 kWh, .13kW and 59.67 therms savings annually per unit (not including fuel substitution measures).

LIFT 2.0 was specifically designed to address the remaining obstacles for income-qualified multifamily properties to accelerate program adoption. Low-income multifamily program participant faces myriad obstacles for accessing and engaging available energy efficiency programs and while progress has been made in lowering the barriers to entry, there are still several that pose a challenge to participation.

One of the major hurdles is customer acquisition, especially in regards to identifying and enrolling low-income customers residing in NOAH properties**.** The existing ESA programs administered by the IOUs focus primarily on deed-restricted properties,[19] which are more straightforward to identify and qualify for program eligibility. Locating and engaging customers in NOAH properties is more challenging, as is verifying their income, since there is no maximum

[18] D.19-06-022, at p.9
[19] *PG&E Energy Savings Assistance, Multifamily Common Area Measures, Initiative Implementation Plan* at p.18. See at https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_3943-G.pdf

income threshold for renting in NOAH properties. However, in order to have a truly successful whole building multi-family offering, NOAH properties must be included, since they constitute the majority of low-income multifamily buildings and units in MCE's service territory.[20] Hence, MCE's offering will serve all eligible low-income multifamily properties, including both deed-restricted and NOAH multifamily properties. Identifying and enrolling these customers presents a sizeable challenge. However, MCE's network of local government agencies and community organizations have a long-standing history in working with this customer segment and are knowledgeable about how best to identify and approach them. In addition to the challenges relating to identifying customers in NOAH properties, it is also important to ensure that affordability is maintained after EE upgrades have been implemented, as those properties do not fall under the same rent control provisions as deed-restricted properties.

Another customer acquisition barrier is the need to earn the trust of vulnerable and hard-to-reach populations and to address concerns regarding the sharing of personal information (e.g. for income verification). In order to address this customer acquisition barrier, MCE will work with local government partners, such as city and county housing agencies and community action organizations, as marketing, education and outreach ("ME&O") partners to make the first touch with building owners, rather than the individual tenants. Utilizing this approach is anticipated to result in more successful lead generation. This collaboration places credible organizations at an early point of engagement which is a crucial period for gaining program participants' trust.

[20] PG&E Energy Savings Assistance Program and California Alternate Rates for Energy Program Amended 2018 Annual Report, at p.141. The report can be found at http://liob.cpuc.ca.gov/Monthly%20Report/PGE%202019%20(PY2018)%20ESA%20CARE%20Amended%20Annual%20Report.pdf

Furthermore, this partnership will continue throughout the customer engagement process from initial outreach to installation and quality control. Through its close ties with local governments, MCE will also implement specific targeting efforts for particularly vulnerable populations, including residents aging in place and buildings with certain health indicators such as a high rate of asthma.

Once a customer has been identified and approached, the next barrier to overcome is the program complexity. There are two main aspects of program complexity which can play a role in discouraging participation in programs: first, the large number of programs available leading to customer confusion. Second, the numerous program eligibility requirements under the LIFT 2.0 program, including, but not limited to, onerous income verification requirements.

MCE's primary tool to address the first barrier is its proven SPOC model, which MCE has used successfully on EE programs for several years. In addition to guiding participants through LIFT 2.0's requirements and processes, the SPOC provides technical assistance to optimize the measure mix and provides financial assistance if required. In addition, the SPOC helps property owners and managers leverage other clean energy and transportation program offerings aimed at low-income multifamily properties. The SPOC will assist customers in identifying and leveraging the offerings of all available programs to secure the customer the most appropriate and applicable mix of measures along with the financial assistance that accompanies them.

In order to address the challenges associated with the income eligibility threshold, MCE proposes to move beyond income eligibility requirements from the 200% FPG, which CARE and ESA presently use, and instead use 60% AMI as the income eligibility threshold. This aligns with other low-income customer programs such as SOMAH, Self-Generating Incentive Program ("SGIP") Equity, and others. Revising the income eligibility threshold to 60% AMI will allow

LIFT 2.0 to serve vulnerable customers that would otherwise be stranded between the existing ESA offerings and conventional EE programs.

Furthermore, MCE proposes a series of steps to streamline the eligibility verification process. For example, MCE plans to allow for enrollment into LIFT 2.0 for customers enrolled in SOMAH and SGIP Equity, as well as for CARE customers, without requiring additional income verification. MCE will also offer customized assistance through the SPOC to guide customers through the LIFT 2.0 eligibility process.

Delivering the appropriate measures to LIFT 2.0 participants is key to achieving the deep savings, as well as health, comfort and safety benefits, called for by the Commission. Although MCE will collaborate with a third-party implementer to determine the optimal measure mix for LIFT 2.0, measure selection will prioritize innovative EE measures focused on energy and bill savings, helping customers respond to TOU pricing, fuel substitution and improving health, safety, and comfort in the home.

The impending introduction of TOU rates along with rate options like SmartRate and SmartAC from PG&E are other factors that may add confusion to the value proposition of energy efficiency upgrades. To counteract this, MCE offers enhanced education initiatives to introduce these concepts to customers and help them optimize their energy usage to realize bill savings while maintaining or improving the level of service. This effort includes presenting available DR and load shifting opportunities.

Another participation barrier for customers in low-income EE programs is the lack of choice in selecting both the equipment installed and the installation contractor. Property owners, the primary target customer of LIFT 2.0, prefer to have the ability to select specific qualifying equipment and would like to have the option to use a contractor of their choosing. MCE's LIFT

Pilot under the current ESA program cycle has allowed owners this right and proposes to continue this in LIFT 2.0. MCE has found that when the owner has the opportunity to exercise choice they have "skin in the game" and are more likely to feel a sense of ownership in the project leading to higher satisfaction and a greater likelihood of repeat participation and/or referrals to other property owners.

A barrier to the installation of heat pumps is the customer's cost share after rebates and/or incentives, which often can include ancillary project costs, such as upgrades to the electrical panel. The installation of heat pumps can cost over $10,000 and require extensive electrical work. Leveraging other funding sources through the SPOC model will help lower the cost barrier. Furthermore, property owners may agree to projects with significant cost share if the associated non-energy benefits are readily identifiable and realizable.

A final barrier to the installation of heat pumps that MCE recognized under the LIFT Pilot is the shortage of qualified installation contractors. To address this issue, LIFT 2.0 will contain a workforce development and training component for local contractors that will focus on, but is not limited to, training or certifying local contractors on the installation of newer and innovative EE technologies such as heat pumps or DR-enabled EE technologies.

OVERCOMING PARTICIPATION BARRIERS	
CHALLENGES	**SOLUTIONS**
Recruit naturally occurring affordable housing units and ease trust issues	Local governments as ME&O partners
Program complexity and multitude of programs	The applied SPOC model
Income eligibility threshold as a hurdle for participation	Adjust income threshold for regional cost of living and program alignment
Achieving deep savings and impacting tenants' health, safety and comfort	Flexible and innovative measure mix including DR and fuel switching components
Introduction of TOU rates	DR-enabled technologies and tenant education
Overly prescriptive measure and contractor selection process	Promote property owner choice and self-sufficiency
Ancillary project costs	Program leveraging

Figure 3 - Overcoming Participation Barriers

C. PROGRAM GOALS AND BUDGET

1. Program Goals

a. Energy Savings Targets

MCE's proposed energy savings targets are shown in the table below. These goals are based on the annual, per unit savings achieved in the LIFT pilot of 474 kWh, .13kW and 59.67 therms (not including fuel substitution measures).[21] These savings include whole building, common area and in-unit measures. The specific ratio of gas to electric savings may change as a result of the solicitation for a program implementer as the final measure list will be decided on in

[21] While savings are averaged on a per unit basis, they include any savings from whole building or common area measures, averaged by the number of units in a particular property. Per unit average savings are more comparable than per property average savings due to variations in property size.

partnership with the selected implementation partner. As described in more detail below, MCE will present on the proposed measure list and adjusted targets in a public workshop to solicit input from stakeholders and CPUC staff before program launch.

Annual energy savings targets are presented in the table below.

Table 2 - Annual Energy Savings Targets

	PY1	PY2	PY3	PY4	PY5	PY6	Total
kWh	118,500	284,400	402,900	426,600	426,600	426,600	2,085,600
kW	32.5	78	110.5	117	117	117	572
therms	149,18	35,802	50,719.50	53,703	53,703	53,703	262,548

b. Household Targets

LIFT 2.0 will target whole building and in-unit measures at 80 properties and approximately 4,400 units. The number of units to be treated each year to meet those goals is shown in the table below.

Table 3 - Annual Unit Targets

	PY1	PY2	PY3	PY4	PY5	PY6	Total
Unit Targets	250	600	850	900	900	900	4,400

c. Health, Safety and Comfort Goals

MCE will use pre- and post-treatment surveys to track participants self-reported health, safety and comfort. The goal is to increase the average overall reported value to increase when comparing pre-treatment results to post-treatment results.

2. Program Budget

The proposed program budget for LIFT 2.0 is $10,603,955 over six years (2021 – 2026). The excel budget template for the ESA program as specified in the Guidance Decision is included in

Attachment 1. In addition, MCE is providing a more detailed description of the annual budget allocation, as well as the budget by category, in the table below.

The budget categories are defined as:

- **Incentives/EE:** includes incentives paid to property owners or managers as well as the cost of equipment installed in units.
- **Implementation:** includes the cost of a third-party implementer, MCE staff time dedicated to program implementation and costs associated with workforce training.
- **General Admin:** includes costs associated with tracking and reporting and other administrative tasks.
- **Marketing:** includes costs associated with marketing the program such as contracts with local governments or other third parties, materials, and other marketing costs.
- **EM&V**: includes cost associated with the EM&V studies proposed in this application.

Table 4 - Proposed LIFT 2.0 Budget

	PY1	PY2	PY3	PY4	PY5	PY6	Total
Incentives/EE	$375,000	$900,000	$1,275,000	$1,350,000	$1,350,000	$1,350,000	$6,600,000
Implementation	$225,000	$245,000	$266,800	$290,564	$316,471	$316,766	$1,660,601
General Admin	$125,000	$135,000	$145,800	$157,464	$170,061	$183,666	$916,991
Marketing	$48,333	$85,333	$112,507	$119,869	$122,435	$123,362	$611,839
EM&V	$32,222	$56,889	$75,004	$79,912	$81,624	$82,241	$407,893
Total	$805,556	$1,422,222	$1,875,111	$1,997,809	$2,040,591	$2,056,036	$10,197,325

MCE recommends that PG&E transfers MCE's annualized LIFT 2.0 Program budget by January 15 of each year, similar to the process adopted for MCE's administration of general market EE funding.[22]

[22] *Decision Enabling Community Choice Aggregators to Administer Energy Efficiency Programs* ("D.14-01-033"), filed January 23, 2014

D. CUSTOMER ELIGIBILITY AND OUTREACH

1. Income Eligibility Threshold

The San Francisco Bay Area has one of the highest costs of living in the country, making it all the more difficult for the low-income households who live here to cover their basic needs. MCE's service territory, which spans four counties, is home to thousands of low-income households, many of whom are ineligible for low income assistance programs by only a very small margin. Using the 200% FPG threshold as the income eligibility requirement, which CARE and ESA presently use, leaves a significant number of households that are struggling to make ends meet ineligible for low-income EE assistance programs. LIFT 2.0 seeks to move income eligibility requirements from 200% FPG to 60% AMI, thereby aligning LIFT 2.0 with other low-income programs including SOMAH, SGIP Equity, the Low-Income Home Energy Assistance Program ("LIHEAP") and others.

Revising the 200% FPG threshold for ESA participation is appropriate here, where significant barriers exist in reaching vulnerable community-specific populations in multifamily buildings in the Bay Area, where cost of living is far above the national average. The Commission initially tied the ESA income eligibility threshold (of the then called "low-income weatherization" ("LIW") program) to the statutorily mandated income threshold for CARE in 1992 to minimize customer confusion.[23] For LIFT 2.0, where MCE will provide SPOC service, customers will be guided through the process of eligibility screening, hence mitigating the concerns of customer confusion.

---

[23] *Order Requiring Energy Utilities to Revise Income Limits for the California Alternate Rates for Energy (CARE) and for the Low-Income Weatherization Program* ("Resolution E-3439"), issued February 23, 1996 at p.1 (*citing* Resolution E-3254, adopted January 21, 1992)

Further, since 1992, when the Commission linked the income eligibility threshold for LIW/ ESA and CARE together, California has developed several other clean energy and energy efficiency programs geared at low-income customers. All of these newer low-income programs have acknowledged the fact that FPG are an inaccurate metric to establish income eligibility for low-income customers in California and most of them have instead tied income eligibility to AMI.[24] Hence, modifying LIFT 2.0's income eligibility threshold to 60% AMI would not cause customer confusion but would instead ease program leveraging by better aligning eligibility criteria. Second, in the Resolution in 1992, the Commission already exercised its discretion to depart from CARE eligibility thresholds for ESA/LIW programming in adopting certain community specific programs,[25] just as MCE requests the Commission do with its community focused LIFT 2.0 proposal.

Revising the threshold to 60% AMI will allow LIFT 2.0 to serve vulnerable customers that would otherwise be stranded between the existing ESA offerings and general market EE programs. The following table provides a comparison of income eligibility thresholds based on 200% FPG versus 60% AMI in MCE's service territory:

[24] For the SOMAH program, D.17-12-022, *Decision Adopting Implementation Framework for Assembly Bill 693 and Creating the Solar on Multifamily Affordable Housing Program* from December 14, 2017 at p. 62; for the SGIP Equity budget D.17-10-004, *Decision Establishing Equity Budget for Self-Generation Incentive Program* from October 12, 2017 at p.15.
[25] *Order Requiring Energy Utilities to Revise Income Limits for the California Alternate Rates for Energy (CARE) and for the Low-Income Weatherization Program* ("Resolution E-3439"), issued February 23, 1996 at p.2 (*citing* Resolution E-3254, adopted January 21, 1992)

Table 5 - Comparison of FPG Income Thresholds to AMI

No. of persons in a house-hold	200% FPL - Total gross annual household income [26]	Contra Costa County[27]		Marin County		Napa County		Solano County	
		AMI	% AMI equiv. to the 200% FPL	AMI	% AMI equiv. to the 200% FPL	AMI	% AMI equiv. to the 200% FPL	AMI	% AMI equiv. to the 200% FPL
1	$33,820 or less	$81,400	40%	$102,700	32%	$64,300	51%	$60,000	56%
2	$33,820 or less	$93,000	35%	$117,300	28%	$73,500	44%	$68,600	49%
3	$42,660 or less	$104,600	39%	$132,000	31%	$82,700	49%	$77,200	55%
4	$51,500 or less	$116,200	42%	$146,600	34%	$91,800	54%	$85,700	60%
5	$60,340 or less	$125,500	46%	$158,400	36%	$99,200	58%	$92,600	65%
6	$69,180 or less	$134,800	49%	$170,100	39%	$106,500	62%	$99,500	70%
7	$78,020 or less	$144,100	52%	$181,800	41%	$113,900	65%	$106,300	73%
8	$86,860 or less	$153,400	54%	$193,600	43%	$121,200	68%	$113,200	77%

2. Eligibility Verification

In order to streamline income eligibility verification under the LIFT 2.0 program, MCE proposes to accept proof of participation in the SOMAH, SGIP Equity, and LIHEAP program as proof of eligibility for LIFT 2.0 as those programs' income eligibility threshold is also set at or below 60% AMI and income verification is required upon program enrollment. Customers participating in California's Low Income Weatherization Program ("LIWP") may also be eligible

[26] Before taxes based on current income sources. Valid through May 31st, 2020.

[27] County AMI data from https://www.huduser.gov/portal/datasets/il/il2019/2019summary.odn

for LIFT 2.0 but will need to undergo additional income verification since LIWP income eligibility is less stringent (at or below 80% AMI) than LIFT 2.0.[28] Furthermore, MCE proposes that no additional income verification is required for customer that are already enrolled in the CARE rate as customers enrolled under CARE fall under the more stringent income eligibility requirements of having to be at or below 200% FPG. Finally, MCE intends to continue implementing the successful elements of the income verification process established under the LIFT Pilot:

1. Property owner affidavit to serve as tenant income verification in deed-restricted properties
2. All the units in a multifamily building qualify for measures offered by the program if at least 80% of all units are occupied by income-qualified households. To qualify for common area measures ("CAM") offered by the program, at least 65% of all units must be occupied by income-qualified households.
3. One application to MCE will provide access and assistance to all the low-income programs offered by MCE, including but not limited to LIFT 2.0, GHHI, MCE's low-income EV program MCEv and MCE's low-income solar program.

MCE's SPOC will provide excellent customer support in helping property owners, managers and tenants through the application process and are flexible to work with property managers in the manner that best suits the property. Online applications will be encouraged for expedited application processing. Program staff will also visit the property in person with the form available on a tablet for those who do not have access to the internet. In cases where tenants are not available or comfortable to fill out online forms, hardcopy applications will continue to be

[28] This eligibility verification process is dependent on approval of MCE's proposed eligibility threshold.

available. These eligibility verification simplification steps will encourage greater participation and will bring in customers that have been reluctant to enroll due to cumbersome verification process.

3. Prioritization of Target Participants

LIFT 2.0 focuses on offering service to customers that have been underserved and/ or have a specific need that makes them particularly vulnerable. While the program will be available to all eligible low-income multifamily properties, LIFT 2.0 will run targeted outreach campaigns to recruit particularly vulnerable or hard-to-reach customers in key segments.

a. Outreach to Naturally Occurring Affordable Housing Properties

NOAH properties are challenging to identify as these properties are not included in government datasets as low-income housing. Because of this challenge, low-income EE programs have traditionally focused on the more readily identifiable deed-restricted properties as evidenced by the eligibility requirements of ESA-CAM[29] and other programs. In the initial LIFT Pilot, MCE conducted an analysis to identify areas with a high probability of NOAH properties. This analysis combined several data sources and included data on (1) geospatial data including county, GEO ID and Census Block Group; (2) customer data such as CARE participation, late payments, LIHEAP participation; and (3) American Community Survey Data such as food stamps recipient and median home value. From this, census blocks are assigned a rank that indicates a potentially high prevalence of low-income households. The heat map provided below is the result of the analysis and is used to target program outreach.

---

[29] *PG&E Energy Savings Assistance, Multifamily Common Area Measures, Initiative Implementation Plan* at p.18. See at https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_3943-G.pdf

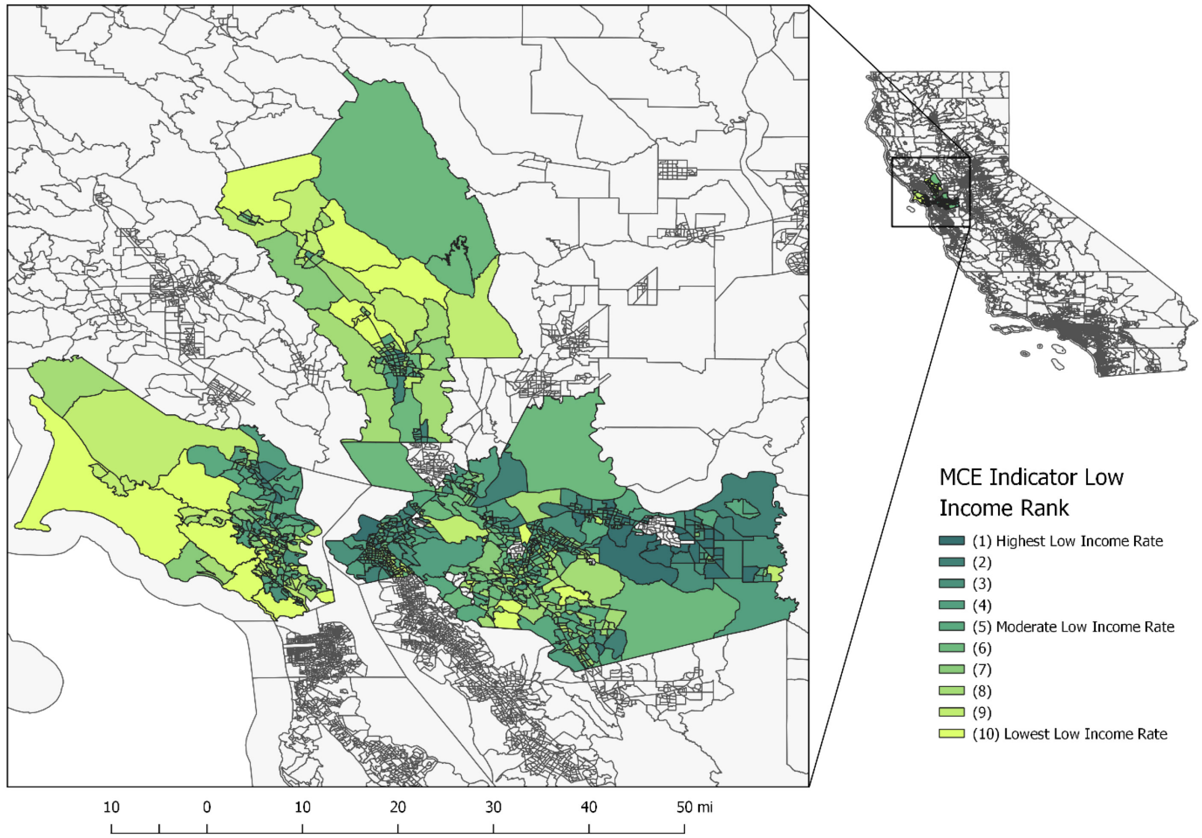


Figure 4 -MCE Indicator of Low-Income Households

Under LIFT 2.0, MCE will continue to deepen the data analysis to identify NOAH properties and will engage community organizations (food banks, places of worship, advocacy groups, etc.), as well as local government partners, to assist in identifying and approaching these NOAH properties.

b. Outreach to Vulnerable Populations through Local Government Partners

One example of how MCE can partner with local agencies in the outreach for LIFT 2.0 is the partnership with GHHI Marin, under which MCE delivers health and safety related information and measures into properties with large populations of aging and elderly residents. This population is sensitive to energy costs because many of them are on fixed incomes and would benefit from

EE measures that will reduce utility bills. MCE partners with the Aging and Adult Services Division of the Marin Health and Human Services and other community service providers to conduct outreach for current program offerings. MCE is planning on deepening this coordination under LIFT 2.0.

Another example of partnering with local governments to conduct targeted outreach can be seen in MCE's efforts over the last year to develop a business plan for working with the Contra Costa County health program. The business plan development is a joint effort of MCE, Contra Costa County and GHHI, and funded by the United States Environmental Protection Agency ("EPA"). The business plan outlines how MCE can work with Contra Costa County agencies to identify properties with a high incidence of asthma and provide health services and EE upgrades through a single program.

MCE will continue to seek out partnerships such as these to target the community members most in need of EE upgrades and recruit them to participate under LIFT 2.0.

4. Maintaining Affordability

Participating in LIFT 2.0 may have the unintended consequence of negatively impacting the affordability of housing for participants by raising the value of the property treated (therefore motivating landlords to increase rent) and/or by increasing the energy bill as a result of electrification and the rebound effect (using efficient/operational equipment more often). To address these matters, MCE proposes implementing affordability and bill protection measures modeled after approaches proposed for the SJVDC Pilot.

MCE plans to utilize the following measures proposed by stakeholders in SJVDAC pilot in order to maintain affordability in NOAH properties:

1. Affidavit signed by landlord, tenant, and MCE which limits the rent increases and evictions (except for just cause) for a period of five years;
2. Enforcement of Affidavit terms includes a claw back provision to recover program costs in the event of landlord breach;
3. Owners responsible for providing rent information to MCE for monitoring; and
4. Annual reporting of monitoring and enforcement activities to Commission through the program's Annual Report.

Moreover, MCE will periodically (at least annually) revisit and assess these measures in order to ensure that they are working to preserve affordability and to implement new measures if these are not adequately protecting tenant affordability. MCE will confer with stakeholders to assess and improve, where necessary, tenant protection measures.

E. SOLICITATION PROCESSES AND TIMELINE

As required by D.19-06-022,[30] MCE intends to release a competitive Request for Proposals ("RFP") and enter into a contract for third-party program design and implementation services for LIFT 2.0. MCE will require bids to cover its full-service area of four counties and 30 cities and towns. MCE may also issue solicitations for a direct install service provider, marketing partners and an EM&V contractor. MCE is aware of the existence of a number of qualified EE firms who would be well-equipped to manage the day-to-day operations of the program at a reasonable cost.

1. Solicitation Processes and Timeline

This section aims to outline the typical timeline and procedure that MCE follows soliciting for services and contracting with third parties, based on the experience under MCE's general

[30] D.19-06-022 at p.9

market EE programs. MCE will release a RFP to a broad distribution list, which includes a variety of MCE stakeholders, partners, community members, program specialists, as well as individuals who have completed the interest forms for solicitations on MCE's website . The RFP may also be posted to social media (e.g. LinkedIn), or highlighted as a post on the MCE website. The solicitation will remain open for a period of no less than 30 days. Prior to the submission deadline, MCE will provide an opportunity for interested parties to submit questions.

MCE will designate a panel of staff members to evaluate proposals and interview top ranked bidders. The panel will score proposals using the criteria outlined below. Once selected, the winning bidder and MCE will collaborate to develop a mutually agreeable Scope of Work and Payment Schedule. These two documents, in combination with MCE's standard contract terms, constitute the draft Contract. Once the selected vendor and the MCE Contracts team have agreed to the draft Contract terms, the Contract will be presented in front of the MCE Board. The Contract must be approved by MCE's Board before it can be executed. It takes on average 60 days from the release of the RFP to the selection of a vendor and submittal of the contract request form. Following the submittal of the contract request form, it may still take up to two months to introduce a pre-negotiated contract to the MCE Board.

In summary, MCE expects to follow the timeline outlined below to launch the program following the approval of MCE's program proposal. This schedule is based on MCE's experience launching third-party designed and implemented programs under the general market EE program.[31]

[31] The process that MCE will go through to launch the LIFT 2.0 program may differ based on the final program design.

Table 6 - Program Launch Timeline

Task	Time after program approval
Issue Solicitation	4 weeks
Vendor Selection	3 months
Executed Contracts	5 months
Stakeholder Workshop on Program Design	6 months
Launch Program	7 months
Reporting	monthly, quarterly, annually

2. Evaluation Criteria

MCE will evaluate proposals using the following criteria, with a percentage allocation assigned to each evaluation criteria:

Table 7 - Solicitation Evaluation Criteria

Industry Experience	20%
Alignment of Proposal with MCE Goals & Objectives	40%
Completeness of Proposal	20%
Pricing	20%

F. PROGRAM DESIGN AND DELIVERY

1. The Applied SPOC Model

MCE prides itself in providing excellent customer service to program participants while also ensuring that customers can easily take advantage of all the clean energy program offerings they may be eligible for. These "guiding principles" for program implementation are embedded in MCE's SPOC model, under which MCE provides real-world, day-to-day support to program participants to make participation in a clean energy programs as simple as possible for customers. MCE proposes to continue the successful SPOC model under LIFT 2.0 with proposed enhancements to provide even greater customer service and support. The SPOC model aims to deliver the following:

- Excellent customer support;

- Tenant education;
- Customer choice and self-sufficiency; and
- Program leveraging.

a. Excellent Customer Support

The SPOC will ease customer participation in LIFT 2.0 by serving as the "go to" resource for any questions, guidance, or other needs the customer may have. The SPOC will not only facilitate customer enrollment under LIFT 2.0 but will also guide customers through the program from start to finish once enrolled. Program support includes providing technical assistance to property owners in bidding out work and selecting a contractor. The SPOC will also work with property owners to phase projects as needed to allow for EE upgrades to occur at a time that is convenient for the property owner (for example to coincide EE upgrades with other general building remodels or building refinancing). In projects that involve fuel substitution, the SPOC will enroll participants in an all-electric baseline after the installation of the heat pump to avoid unnecessary charges.

b. Tenant Education

Following the installation of EE measures, the SPOC will continue to provide customer support, mainly focused on tenant education regarding the benefits of EE upgrades and the operation of EE equipment. For example, the SPOC will provide education to LIFT 2.0 participants regarding heat pump operation by arranging hands-on trainings by the program implementer about the operation of the heat pump equipment and/or by directing the customer to online tutorials. MCE will also provide language appropriate materials where necessary. MCE's third-party implementer will work with installation contractors and manufacturers' representatives to ensure that the training materials cover the basics of operation and that customers are well informed about equipment operation.

MCE will similarly provide tenants education to help them save money under a TOU rate structure. The exact nature of this training will be determined through the third-party solicitation process.

c. Customer Choice and Self-Sufficiency

As in the LIFT Pilot, MCE encourages customer choice in LIFT 2.0 for selecting specific equipment, as well as for choosing their preferred installation contractor. Providing participants agency in the contractor and equipment decision-making process leads to higher satisfaction and greater likelihood of repeat participation and/or referrals to other property owners. During the selection process, the SPOC is available to provide guidance to program participants as needed.

d. Program Leveraging

Traditional clean energy and EE program offerings are often siloed from other services and programs, which creates a burdensome and confusing enrollment process for customers. MCE's SPOC model provides behind-the-scenes coordination with various programs and funding resources in order to provide its customers with the comprehensive services they need. By creating partnerships with local service providers and leveraging different program offerings, MCE is able to reach new customers while streamlining program enrollment and breaking down the barriers to program participation. Additionally, program leveraging through the SPOC will enable customers to take advantage of all the programs available to them, thereby maximizing the benefit to the customers and improving the value of all leveraged programs.

Under LIFT 2.0, MCE will continue to build upon the success of the Applied SPOC model under the LIFT Pilot while applying specific lessons learned to further improve program efficiencies and ease customers' program participation. MCE will approach program leveraging in stages, focusing initially on programs that are naturally well-suited to be leveraged with the LIFT 2.0 program, and then addressing other programs that may only be suited for certain multifamily properties under certain circumstances. This ensures that the SPOC model is implementable in real-life, time and resource-constraint scenarios where customers and the SPOC can focus on the programs that offer the largest value first before exploring additional leveraging opportunities.

Level 1: Leveraging EE programs

As a first step, MCE will leverage other EE programs that may be available to income-qualified customers participating in LIFT 2.0. MCE has ample experience leveraging MCE's general market MFES program for EE rebates. Additionally, MCE is already coordinating with PG&E and the Bay Area Regional Energy Network ("BayREN") on general market EE programs to ensure that customers interested in EE program offerings will be channeled toward the appropriate program. MCE expects that similar procedures would be developed under the umbrella of the ESA MFWB program so that PAs can coordinate and avoid duplicating marketing efforts and customer confusion.

MCE also plans to continue utilizing LIFT 2.0 as the backbone of its GHHI partner programs. In doing this, MCE enables LIFT 2.0 customers to receive a comprehensive assessment, scope of work and technical assistance that covers EE measures and home hazard modifications specific to their region. Currently, GHHI Marin provides up to $2,250 for health, safety, accessibility or energy efficiency measures per qualified multifamily unit and provides a customer referral pipeline focused on serving customers that have an immediate health need. GHHI Contra Costa is a new partnership with Contra Costa Health Services to build out a similar program but focus on indoor asthma trigger mitigation, since asthma management is the greatest health need for Contra Costa residents.

In addition, MCE will coordinate with the California Community Services Department ("CSD") and Association for Energy Affordability ("AEA"), the implementer of the LIWP, to monitor the availability of services and financial support from LIWP. Customers eligible for LIFT 2.0 are eligible for LIWP offerings so no additional qualifying step is required. At present, the demand for LIWP services exceeds current funding allocated so it is unlikely that MCE will be able to leverage this additional resource.[32] However, MCE will continue to monitor developments in LIWP funding to optimize leveraging opportunities. CSD also administers LIHEAP and the Weatherization Assistance Program ("WAP") which are federally funded programs. These programs prioritize serving the most vulnerable low-income populations (e.g., households with high energy burdens and households with elderly, disabled, and/or young children). MCE will work with CSD to identify these households in order to maximize the benefits available from a combined offering.

Level 2: Leveraging Renewable Energy and Clean Transportation Programs

As a second step, MCE will investigate leveraging opportunities with other clean energy and clean transportation programs offered to income qualified customers in California.

[32] *CSD, Low-Income Weatherization Program Guidelines* from November 10, 2015 and last updated on January 22, 2019 at p 1. The document can be found at https://www.csd.ca.gov/Shared%20Documents/LIWP-MF-Program-Guidelines-Amended-2019.pdf

MCE plans to collaborate with the AEA, Center for Sustainable Energy ("CSE"), and GRID Alternatives (the PA team) on the SOMAH Program. SOMAH provides financial incentives and technical assistance to install solar PV systems on low-income multifamily buildings. Under SOMAH, program participants are required to have an EE audit performed, or have installed EE measures in the last three years, and to have a referral to the ESA program.[33] MCE envisions working with the SOMAH PA team to co-market SOMAH and LIFT 2.0 in MCE's service territory and to develop streamlined processes for direct referrals between the two programs. As an example of joint program marketing, LIFT 2.0 enrollees could be presented with a detailed description of SOMAH along with a preliminary value proposition for adding solar during their initial technical assessment under LIFT 2.0. Presently, SOMAH is fully subscribed for the first year and a waitlist is in place. However, efforts to market SOMAH continue and MCE views the Program as a strong channel for enrollees into LIFT 2.0.

In addition to leveraging the SOMAH program for LIFT 2.0 participants, MCE will also investigate opportunities for properties to participate under MCE-funded low-income solar programs. For example, master metered low-income multifamily properties currently don't qualify for SOMAH due to virtual net energy metering ("NEM") requirements. These properties can participate in MCE's low-income solar program and LIFT 2.0 participants will be referred to the appropriate solar programs according to the specific characteristics of their property.

Another program that offers energy related incentives to low-income households is the SGIP. CPUC Decision 19-09-027 from September of 2019 approved two new components of the

[33] D.17-12-022 at p.27

SGIP that could be interesting to LIFT 2.0 participants.[34] First, D.19-09-027-adopted a carve out for heat pump water heater incentives for equity customers under the SGIP.[35] MCE will assist customers in combining the SGIP incentive and LIFT 2.0 offering where possible and appropriate to bring down the cost of heat pump installations. Second, MCE will identify LIFT 2.0 participants that may be candidates for energy storage under the SGIP Equity Budget. Lastly, MCE will monitor the Commission directed Thermal Energy Storage Working Group's assessment of expanding the SGIP-eligibility of heat pump water heaters beyond the existing equity set aside. The outcome of this working group may result in additional funds being made available for heat pump water heater implementation.

A third program that MCE will leverage for LIFT 2.0 program participants is the Disadvantaged Communities Green Tariff ("DAC-GT") program that the Commission authorized in D.18-06-027 in June of 2018. The DAC-GT program is a community solar program that offers low-income customers 100% solar energy through community solar installations in DACs in California, while receiving 20% discount on the electric portion of their bill. MCE is currently working on developing this program and expects to roll it out to customers in late 2020. Once available, MCE will ensure that tenants who participate in LIFT 2.0 learn about the DAC-GT program and enroll if interested and eligible. Vice versa, MCE will ensure that customers who live in multifamily properties and express interest in the DAC-GT program learn about LIFT 2.0 and

[34] D.19-09-027, *Decision Adopting a Self-Generation Incentive Program Equity Resiliency Budget, Modifying Existing Equity Budget Incentives, Approving Carry-Over of Accumulated Unspent Funds, and Approving $10 Million to Support the San Joaquin Valley Disadvantaged Communities Pilot Projects*, from September 18, 2019.
[35] See D.19-09-027, OP 5 at pp.126-127

establish a channel of communication to the property manager and/or owner to discuss potential participation in LIFT 2.0 for the property as a whole.

Finally, MCE will investigate opportunities for LIFT 2.0 participants to take advantage of MCE's electric vehicle program offerings for income qualified customers, titled MCEv, which include rebates for charging infrastructure and electric vehicle purchases.

Level 3: Customized Leveraging Support

For certain customers and properties, MCE will investigate additional leveraging opportunities on a case-by-case basis. Financing programs available from PG&E, BayREN, and the California Hub for Energy Efficiency Financing ("CHEEF") can add to the project value proposition by reducing or eliminating the customer's upfront costs and using the energy savings from the project to pay off the loan. If a customer could benefit from financing, MCE's SPOC will direct customers to either PG&E's on-bill financing ("OBF") program, BayREN's Bay Area Multi-family Capital Advance Program ("BAMCAP"), or Go Green Financing depending on the customer's circumstances and preference. These financing programs can allow for deeper savings by removing the financial obstacles to comprehensive retrofits.

As directed by AB617, the California Air Resource Board under its Community Air Protection Program ("CAPP") has selected the Richmond area for a Community Health Protection Program. This program mandates developing an air monitoring plan, gathering stakeholder feedback, and eventually developing a Community Emissions Reduction Plan to address the air quality in the community. With the City of Richmond being a valued community within MCE's service territory and an area of focus for the LIFT 2.0 program, MCE will participate as a stakeholder and provide feedback on the Community Emissions Reduction Plan with special attention focused on health and safety measures being offered by LIFT 2.0.

Earlier this year, the Commission instituted a rulemaking on building decarbonization which included the implementation of SB1477.[36] SB1477 includes a directive for two programs aimed at decarbonizing buildings. One of the Programs is the Technology and Equipment for Clean Heating ("TECH") program, which aims to transform the market for heat pump space and water heating technology "through upstream market development, consumer education, contractor and vendor training, and the provision of upstream and midstream incentives." MCE will closely monitor the developments of the TECH Program and will leverage the offering where appropriate.

Lastly, MCE will leverage residential DR providers as an additional outreach partner to promote heat pumps, smart thermostats, and other remote-controllable measures to target customers. MCE will also promote residential DR services as a way for customers to add an additional value stream to their home upgrades.

[36] R.19-01-011, *Order Instituting Rulemaking Regarding Building Decarbonization*, from January 31, 2019.

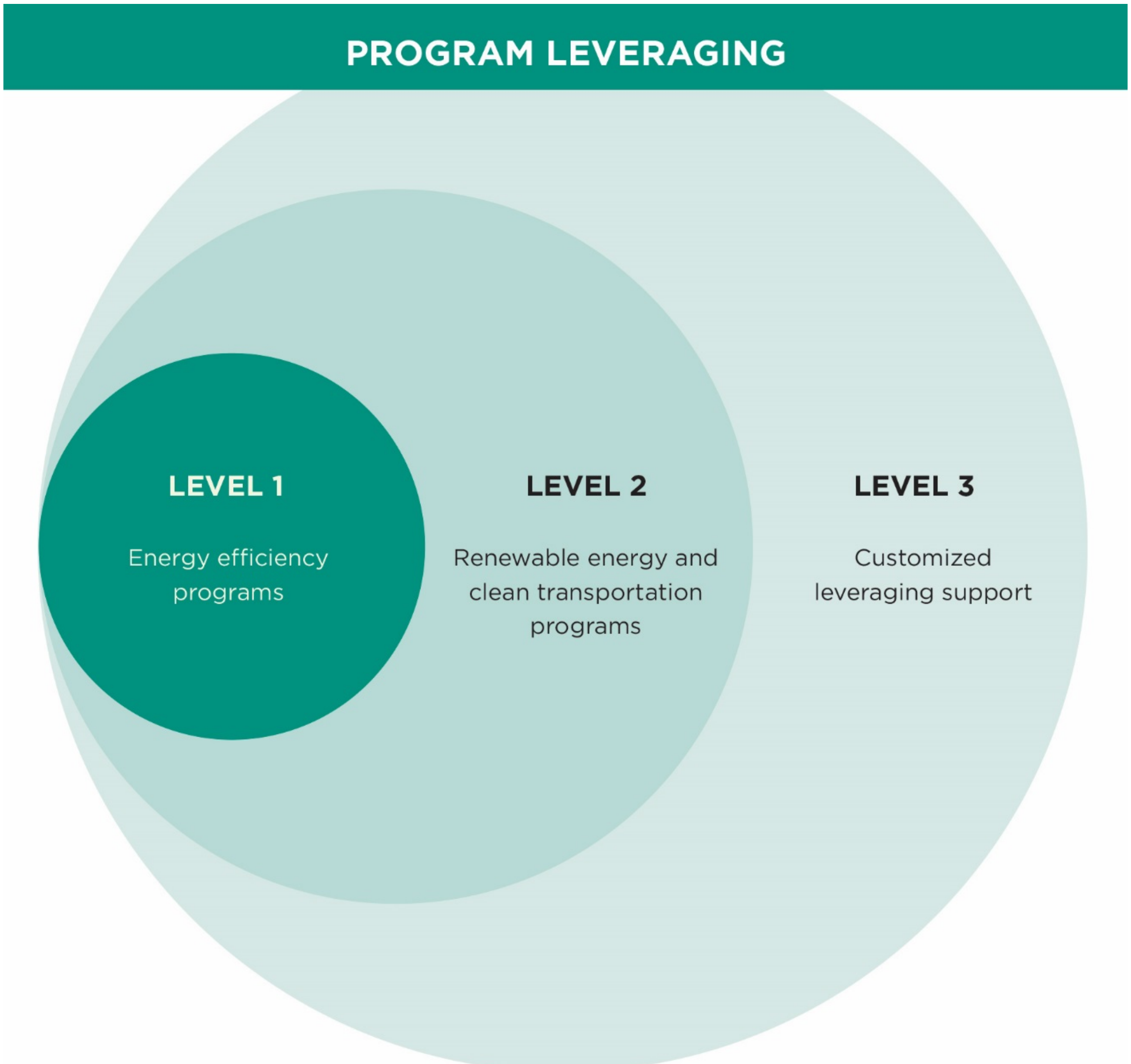


Figure 5 - Program Leveraging

2. Portfolio Composition

a. Measures under LIFT 2.0

MCE proposes a balanced portfolio of measures to achieve energy savings and reduce energy cost burden, increase health, safety, and comfort, and reduce greenhouse gas ("GHG") emissions. In addition, MCE will prioritize measures that will benefit the specific target populations as described earlier in this proposal. MCE plans to apply the successful measures of the LIFT Pilot, including heat pumps, along with new technologies such as smart thermostats and grid-connected water heaters. Lastly, MCE will apply the findings from the 2019 Energy Efficiency Potential and Goals Study to inform the selection of additional pilot measures.

The exact measure mix under LIFT 2.0 will be determined under a collaboration with the selected third-party implementer, as it is standard practice for third-party implemented programs. MCE will request that bidders include a proposed measure list in their proposals. Once an implementer is selected, MCE will work with that partner to refine the list of measures. Prior to finalizing the measure mix, MCE will present the proposed measure list to stakeholders in a public workshop to solicit feedback. This workshop will be noticed through the service list, included on MCE website, and sent directly to members of MCE's Community Power Coalition, among others.

The LIFT Pilot provided MCE insight on implementing heat pumps in low-income multifamily properties and using this experience, MCE plans to continue to offer this measure in LIFT 2.0. Depending on the layout of water heating and space heating systems of the multifamily building, heat pumps may be a common area measure (shared by more than one tenant) or an in-unit measure. In either location, heat pumps provide health benefits by eliminating combustion gas emissions. Despite the forthcoming availability of heat pump measures in the general market EE portfolio,[37] MCE anticipates that the customer cost share for these measures will be prohibitive for low-income customers. MCE believes that a heat pump offering targeted at low-income households is important from an equity vantage point. With this in mind, MCE will leverage programs (e.g. SGIP Equity) that promote heat pump installation and will closely coordinate with their efforts.

[37]D.19-08-009, *Decision Modifying the Energy Efficiency Three- Prong Test Related to Fuel Substitution,* from August 1, 2019

In addition, LIFT 2.0 will promote measures that allow tenants more control and flexibility over their energy use. Measures located in unit such as smart thermostats and grid connected heat pump water heaters would enable customers to shift load away from high cost TOU periods (saving them money) as well as participate in residential DR programs (earning them money), further reducing energy hardship. Moreover, in addition to these measures providing customer benefits, they provide system benefits by reducing demand during peak energy use periods.

b. Cost Effectiveness

MCE recognizes that the Commission's mandate for ESA programs strikes a delicate balance amongst energy and cost savings, NEBs, and value to the ratepayer. NEBs are a unique priority within ESA programs and are integral to addressing equity issues in low-income communities. Some NEBs likely to be realized under LIFT 2.0 include positive health outcomes like fewer sick days and lower prevalence of asthma; improved equipment performance resulting in higher comfort; and economic benefits such as deferred replacement of equipment and appliances. Furthermore, the Commission supports a policy of reducing the energy-related hardships facing low-income households which LIFT 2.0 directly addresses.

Keeping this in mind, MCE's LIFT 2.0 program aims to deliver optimized energy services to low income households that provide health, safety, and comfort improvements while saving energy and lowering utility bills, all within a cost-effective framework. Although there is no cost effectiveness threshold requirement for the LIFT 2.0 program, MCE will track cost effectiveness at the measure and program level, as outlined in D.16-11-022,[38] and will use this information to inform current and future measure offerings.

[38] D.16-11-022 at pp. 191-192.

MCE also intends to follow the findings of the ESA Program Cost Effectiveness Working Group and incorporate recommendations as they are issued. Finally, MCE supports the inclusion of additional NEBs into the ESA cost effectiveness tool ("ESA-CET") as identified in *NEB/NEI Study for the California ESA Program*.[39]

3. Workforce Development and Training

MCE's mission is "to address climate change by reducing energy related greenhouse gas emissions through renewable energy supply and energy efficiency at stable and competitive rates for customers while providing local economic and workforce benefits." In keeping with our mission, LIFT 2.0 will provide a home performance education component targeting local contractors. Recognizing that there is a significant ESA workforce that are experienced in working in the residential low-income sector, MCE's LIFT 2.0 program will actively seek out those contractors and provide onsite home performance education for their first set of upgrades within the program. This education will reap two benefits: it will create a relationship between MCE, program implementers, and the contractors entrusted with carrying out the home upgrades in the multifamily properties, and it will provide an opportunity to educate contractors about the benefits of a whole-home approach to EE upgrades.

Under the LIFT Pilot, MCE recognized that the main challenge to promoting the installation of heat pumps on a broader basis is the shortage of qualified heat pump installation contractors. As part of LIFT 2.0, MCE will focus on developing workforce training and education opportunities with current ESA contractors and other contractors to increase the qualified heat

---

[39] Skumatz, Lisa A. "Non-Energy Benefits and Non-Energy Impact (NEB/NEI) Study for California Energy Savings Assistance (ESA) Program", 2019. To be found at https://pda.energydataweb.com/api/view/2289/ESA%20NEB%20Study%20Draft%20Report%20Volume1.pdf

pump contractor pool. The skills to perform this work requires extensive training and is invaluable for the movement towards building electrification.

MCE plans to partner with local community colleges and vocational schools that specialize in HVAC/R training such as Diablo Valley College, Solano Adult Education, and Los Medanos College to promote education and training opportunities for local contractors to provide the skills to continue helping the community transition to a clean energy future. MCE will concurrently leverage these same workforce development channels to recruit low-income and underemployed individuals seeking jobs in the home performance industry. By providing opportunities for work through LIFT 2.0, MCE can forge relationships with educational institutions by informing them of the opportunities for education and training needed to fill existing gaps in the EE workforce. Specifically, MCE will encourage vocational schools and community colleges to offer training in developing scopes of work for EE projects through a home performance approach, as well as heat pump installations and maintenance.

4. Project Implementation and Quality Control Processes

While the details of the program implementation and quality control processes of LIFT 2.0 will be determined in the third-party solicitation process, MCE is providing a high-level overview in the following flowchart:

PROJECT IMPLEMENTATION & QUALITY CONTROL PROCESSES

1
COMPLETE ONLINE INTEREST FORM

Interested property fills out LIFT 2.0 Interest Form that is available on MCE's website. MCE schedules an initial call with the property owner to discuss the property's needs, appropriate measures, and determine whether the property would be a good candidate for the program.

2
SUBMIT INTENT TO PROCEED & GOOD FAITH DEPOSIT

Once a property is ready to move forward, MCE sends the property owner an Intent to Proceed form and request a Good Faith Deposit.

3
LIFT INCOME ELIGIBILITY

MCE works with property managers (and individual tenants if necessary) to complete the income verification process based on each individual property's needs.

4
SITE ASSESSMENT & SCOPE OF WORK DEVELOPMENT

The technical assistance (TA) provider completes site assessment and creates a report showing the opportunities available at the property and the total rebate amount for each measure. The TA provider also supports the development of a Scope of Work and can assist in identifying contractors and developing contractor bid packets.

5
MEASURE INSTALLATION

MCE supports the property as need through the measure installation process.

6
POST-INSTALLATION QUALITY ASSURANCE

MCE conducts a post-project inspection to ensure measures were installed according to the Minimum Performance Requirements and MCE's program standards.

Figure 6 - Project Implementation and Quality Control Processes

5. Marketing, Education and Outreach Strategies

MCE will partner with cities and counties within its service territory to market the LIFT 2.0 program, provide outreach to vulnerable customers who otherwise would not be served, and collaborate on resident education. By aligning LIFT 2.0's ME&O efforts with local governments, MCE is able to leverage the local governments' trusted communication channels, which will increase program awareness and participation. In addition to general program outreach, County partners provide access to County-specific vulnerable communities, such as residents facing asthma health risks in Contra Costa County and a high elderly population in Marin. MCE will look to partner with County agencies serving these populations in order to provide comprehensive services and resident education to the people most in need.

MCE will also continue its partnership with BayREN's Bay Area Multifamily Building Enhancement Program ("BAMBE"). MCE and BayREN have created a joint marketing campaign and dual program enrollment for the general market EE multifamily programs. This partnership has enabled a robust referral tree between the agencies' programs and ensures properties are sent through the program or programs that benefit them the most. MCE will work with BayREN to incorporate LIFT 2.0 offerings under this braided program approach where possible.

6. EM&V and Program Metrics

MCE will contract with an independent third-party to perform EM&V and process evaluations and has set aside four percent of total budget for this task. The exact evaluation process for the new round of ESA programs has yet to be determined by the Commission. However, MCE has outlined below a high-level plan of the EM&V activities as envisioned for LIFT 2.0. MCE will also coordinate with the CPUC's evaluation teams to ensure that the program is well prepared for future evaluation requirements and efforts.

EM&V Objective 1: Verify Program Progress towards Key Success Metrics and Enable Real-Time Program Improvement

MCE will track program performance based on a set of key success metrics (including measure level and participant data) that will be developed during the third-party solicitation process. Both participant and measure level data will be collected in real time and analyzed at critical milestones to determine whether specific measures are not performing as expected and whether the program requires mid-cycle modifications. Specifically, MCE is proposing to complete a mid-cycle evaluation of LIFT 2.0 after completing three years of program implementation. The mid-cycle review will track progress to date, analyze the pilot's performance, and suggest revisions to ensure that LIFT 2.0 achieves its goals.

EM&V Objective 2: Quantify the Effect of the Revised Eligibility Criteria and the Targeted Outreach Strategies

The EM&V process will particularly examine the impact of the updated income eligibility requirements and the revisions to the income verification process on program participation. MCE will collect data on: (1) the percentage of participants that would not have been eligible under previous income eligibility thresholds, and (2) the percentage of participants who also leveraged other programs with the same income eligibility thresholds (e.g. SOMAH). MCE will also collect data on how many participants were recruited through targeted outreach via local governments.

EM&V Objective 3: Develop a List of Key Accomplishments, Best Practices and Lessons Learned

MCE will develop a list of program design components that were particularly successful, as well as a list of recommendations for program design improvement through interviews with program participants, implementation staff, and partners.

G. PROGRAM ADMINISTRATION

Based on its experience with the LIFT Pilot and other EE program offerings, it is MCE's belief that program administration for downstream EE programs, especially those dealing with vulnerable populations, is most successful when implemented at the local level. A successful MFWB program requires direct and targeted outreach to low-income multifamily building owners, managers and tenants on an individualized basis. Locally-administered programs are better positioned to provide this outreach as they are sensitive to specific local needs and challenges, as well as more readily able to utilize local agencies as outreach partners. Furthermore, low-income and other hidden and vulnerable populations are not uniform throughout California and vary widely by geographic location. The key to serving these customers is finding them in the first place, which is much easier to do when PAs have a deep familiarity with their geographic footprint.

Additionally, local implementation of the ESA MFWB program allows for more learning opportunities and for the Commission to be able to compare and contrast which local implementation strategies are successful in accelerating the adoption of EE upgrades at low-income multifamily properties.

MCE, as a local CCA, has a close connection to its communities, making it well positioned to implement complex low-income multifamily EE programs. Because of its small size, MCE can be more nimble, responsive, targeted, and innovative in its approach to programs. Moreover, MCE's local governance structure and connection to its local community allow MCE to incorporate community feedback into the development of its programs and also leverage local government partner agencies as outreach mechanisms and for program layering. Customer outreach strategies, especially those targeting low-income customers, are best implemented on a local level through trusted messengers like local governments or community-based organizations to overcome mistrust among vulnerable populations. MCE is uniquely positioned to service its customers by building upon its experience in implementing the LIFT Pilot and by leveraging its close ties to the local community. Because of these qualifications, MCE is best suited to serve as the MFWB local administrator for its service area.

As required by D.19-06-022, MCE intends to release a competitive RFP and enter into a contract for third-party program design and implementation services for LIFT 2.0. MCE will serve as the PA. Third party implementation is an effective program delivery model - utilized frequently in ratepayer-funded EE programs, including MCE's, which acknowledges that different vendors bring unique experience in specific target markets or technology areas. The PA is then able to focus on independent program oversight, budget management, EM&V, and reporting of program impacts. Implementers may not be well-positioned to administer programs, but they are often the most suitable partners for delivering projects and generating program impacts, in growing a network of qualified contractors or installers, leading outreach to stakeholders, and reviewing targeted technologies and their specifications. A model featuring a separate PA and implementer is envisioned as the most impactful, cost-effective approach for LIFT 2.0.

CHAPTER 3: CONCLUSION

MCE thanks the Commission for their thoughtful consideration of the LIFT 2.0 proposal. MCE respectfully requests that the Commission approve the LIFT 2.0 program including the adjustment of income qualification threshold to 60% AMI. The Program aims to break down barriers to reach more low-income households in multifamily buildings and accelerate the adoption of energy efficient measures. With an innovative design and a comprehensive set of measures that deliver deep energy savings and improvements to health, safety, and comfort, LIFT 2.0 will reduce energy burdens and enhance quality of life for vulnerable communities most in need.

CHAPTER 4: ATTACHMENTS

Attachment 1: Excel Attachments

PY 2021-2026 Energy Savings Assistance Program Table A-1a, Proposed Electric & Gas Budget (Multifamily only)
MCE

	PY2020 Authorized	PY 2021 Proposed	PY 2022 Proposed	PY 2023 Proposed	PY 2024 Proposed	PY 2025 Proposed	PY 2026 Proposed
Energy Savings Assistance Program							
Energy Efficiency							
Appliances							
Domestic Hot Water							
Enclosure							
HVAC							
Maintenance							
Lighting							
Miscellaneous							
Customer Enrollment							
In Home Education							
Pilot							
Energy Efficiency Total	$0	$0	$0	$0	$0	$0	$0
Training Center							
Workforce Education and Training							
Inspections							
Marketing and Outreach							
Statewide Marketing and Outreach							
Studies							
Regulatory Compliance							
MF Whole Building Program	$ 874,635.11	$ 1,489,605.92	$ 1,940,191.06	$ 2,059,893.85	$ 2,098,897.23	$ 2,140,731.47	$ 10,603,954.64
General Administration							
CPUC Energy Division							
TOTAL PROGRAM COSTS	$ 874,635.11	$ 1,489,605.92	$ 1,940,191.06	$ 2,059,893.85	$ 2,098,897.23	$ 2,140,731.47	$ 10,603,954.64
Common Area Cost Allocation							
In Unit Cost Allocation							
Communal Area/Shared System Cost							
Funded outside of ESAP Program Budget							
Indirect Costs							
NGAT Costs							

PY 2021-2026 Energy Savings Assistance Program Table A-2a, Proposed Electric Budget (Multifamily only)

	PY2020 Authorized	PY 2021 Proposed	PY 2022 Proposed	PY 2023 Proposed	PY 2024 Proposed	PY 2025 Proposed	PY 2026 Proposed
Energy Savings Assistance Program							
Energy Efficiency							
Appliances							
Domestic Hot Water							
Enclosure							
HVAC							
Maintenance							
Lighting							
Miscellaneous							
Customer Enrollment							
In Home Education							
Pilot							
Energy Efficiency Total	$0	$0	$0	0	$0	$0	$0
Training Center							
Workforce Education and Training							
Inspections							
Marketing and Outreach							
Statewide Marketing Education and Outreach							
Studies							
Regulatory Compliance							
MF Whole Building Program	$ 186,503.94	$ 317,646.40	$ 413,730.03	$ 439,255.68	$ 447,572.84	$ 456,493.65	$ 2,261,207.46
General Administration							
CPUC Energy Division							
TOTAL PROGRAM COSTS	$ 186,503.94	$ 317,646.40	$ 413,730.03	$ 439,255.68	$ 447,572.84	$ 456,493.65	$ 2,261,207.46
Common Area Cost Allocation							
In Unit Cost Allocation							
Communal Area/Shared System Cost Allocation							
Funded outside of ESAP Program Budget							
Indirect Costs							
NGAT Costs							

PY 2021-2026 Energy Savings Assistance Program Table A-3a, Proposed Gas Budget (Multifamily only)

	PY2020 Authorized	PY 2021 Proposed	PY 2022 Proposed	PY 2023 Proposed	PY 2024 Proposed	PY 2025 Proposed	PY 2026 Proposed
Energy Savings Assistance Program							
Energy Efficiency							
Appliances							
Domestic Hot Water							
Enclosure							
HVAC							
Maintenance							
Lighting							
Miscellaneous							
Customer Enrollment							
In Home Education							
Pilot							
Energy Efficiency Total	$0	0	0	0	0	0	0
Training Center							
Workforce Education and Training							
Inspections							
Marketing and Outreach							
Statewide Marketing Education and							
Studies							
Regulatory Compliance							
MF Whole Building Program	$ 688,131.17	$ 1,171,959.52	$ 1,526,461.03	$ 1,620,638.16	$ 1,651,324.39	$ 1,685,237.82	$ 8,342,747.18
General Administration							
CPUC Energy Division							
TOTAL PROGRAM COSTS	$ 688,131.17	$ 1,171,959.52	$ 1,526,461.03	$ 1,620,638.16	$ 1,651,324.39	$ 1,685,237.82	$ 8,342,747.18
Common Area Cost Allocation							
In Unit Cost Allocation							
Communal Area/Shared System							
Funded outside of ESAP Program Budget							
Indirect Costs							
NGAT Costs							

PY 2021-2026 Energy Savings Assistance Program Table A-5, Portfolio Goals and Target Populations
MCE

	Electric Savings						Demand Savings				Gas Savings						GHG Savings				Combined (Electric and Gas) Savings			
	Aggregate Values			Annual Goals		Annual Metric [3]	Aggregate Values			Annual Goal	Aggregate Values			Annual Goals		Annual Metric [3]	Aggregate Values			Annual Metric [3]	Aggregate Values			Annual Metric [3]
Target Populations	Total Potential (kWh)	Total Goal (kWh)	Total Participation Goal (HH)	Average Annual Resource Electric Savings per Household (kWh/HH/yr)	Average Annual Non-Resource Quantitative Goal per Household (units/HH/yr)	Average Annual household hardship reduction indicator (units/HH/yr) [4]	Total Potential (kW)	Total Goal (kW)	Total Participation Goal (HH)	Average Annual Resource Demand Savings per household (kW/HH/yr)	Total Potential (therms (MM))	Total Goal (therms (MM))	Total Participation Goal (HH)	Average Annual Resource Gas Savings per Household (therms(MM)/HH/yr)	Average Annual Non-Resource Quantitative Goal per Household (units/HH/yr)	Average Annual household hardship reduction indicator (units/HH/yr) [4]	Total Potential (GHG (Tons))	Total Goal (GHG (Tons))	Total Participation Goal (HH)	Average Annual GHG Savings per household (GHG (Tons)/HH)	Total Potential (kBTU)	Total Goal (kBTU)	Total Participation Goal (HH)	Average Annual kBTU Savings
Housing Type																								
Single Family																								
Multifamily [1]		2,085,600	4400	474				572	4400	0.13		262.548	4400	0.059								1896122	4400	430.937
Mobile Homes																								
Housing Total	0	0	0			0	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0
Customer Type																								
Disadvantaged																								
Tribal Communities																								
Other ESA-eligible																								
CARB-Identified																								
Customer Total	0	0	0			0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0
Climate Zone																								
1																								
2																								
3																								
4																								
5																								
6																								
7																								
8																								
9																								
10																								
11																								
12																								
13																								
14																								
15																								
16																								
Climate Zone Total	0	0	0			0	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0
Other Category																								
[Enter Category Name]																								
[Enter Category Name]																								
[Enter Category Name]																								
[Enter Category Name]																								
Customer Total	0	0	0			0	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0

*Optional categories to fill-in. Housing Type and Customer Type are mandatory.
[1] For the purposes of this Application, consider a multifamily building has at a minimum five or more units.
[2] As designated by CalEPA using their CalEnviroScreen Tool
[3] Include both Resource and Equity measures in calculation
[4] Cite source of rates used to calculate any bill savings

Energy Savings Assistance Program Table A-6a, Detail by Housing Type (Multifamily only) MCE

		PY 2021 Projected Customers Treated	PY 2022 Projected Customers Treated	PY 2023 Projected Customers Treated	PY 2024 Projected Customers Treated	PY 2025 Projected Customers Treated	PY 2026 Projected Customers Treated
Gas and Electric Customers							
Owners - Total							
	Properties						
	Multifamily Tenant Units	250	600	850	900	900	900
	Units Treated						
Electric Customers (only)							
Owners - Total							
	Properties						
	Multifamily Tenant Units						
	Units Treated						
Gas Customers (only)							
Owners - Total							
	Properties						
	Multifamily Tenant Units						
	Units Treated						

NOTES

1 Multifamily buildings are defined as 5 or more units

2 Property is a collection of one or more buildings that constitute a multifamily property

3 Multifamily tenant units are provided here to give a sense of the number of low-income households impacted through treatment of a whole building treatment or common area measures 4 "Units Treated" should only be completed for units not captured in A-6 as part of a whole building treatment where measures are installed in common areas and in units

A.14-11-007 ALJ/KK3/ilz

Attachment 2: LIFT Pilot Measures

Table 8 - LIFT Pilot Measures

Measure
Low Flow Bath Aerator
Low Flow Kitchen Aerator
Low Flow Showerhead
T24 Compliant Windows ($/sqft)
R-19 Crawlspace Insulation ($/sqft)
In Unit Energy Star Laundry Washer
Hardwired In Unit LED Fixture
Hardwired In Unit LED Retrofit
Duct Sealing/Replacement
R-13 Wall Insulation
R-30 Blown Insulation
Energy Star Refrigerator
Energy Star Water Heater
Tankless Water Heater
Split/PTAC Air Conditioner
Window AC Unit (SEER >11)
Smart Thermostats

CHAPTER 5: APPENDICES

Appendix A: Statement of Qualifications for Alice Havenar-Daughton

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

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

Q2: Please describe your background.

A2: In this role, I oversee the design, implementation, and evaluation of EE programs that help customers reduce energy usage and save on their utility bills. Prior to my promotion to Director, I successfully transitioned our Single-Family Program to a more efficient model that now serves over 10,000 customers a year and generates an average of 2-8% savings per home. I have been working with EE programs since I began at MCE in July of 2014. Prior to this, I worked at Opinion Dynamics Corporation as a Senior Analyst. I served as the lead analyst, where I performed process and impact evaluations of EE and DR programs in California and across the country. I have also worked for the Alliance for Climate Protection as a Fellow, where I focused on analyzing national climate and energy legislation to support renewable energy advocacy efforts. My resume is attached as Appendix B.

Q3: What is the purpose of your testimony?

A3: As the Director of MCE's Customer Programs, I am proposing an innovative program to facilitate the implementation of EE upgrades at income qualified multifamily properties in our service territory. These communities are particularly difficult to serve and require a specialized, local perspective in program design. Details about the program are included in Chapters 1 to 4 of this testimony.

Q4: Does this conclude your statement of qualifications?

A4: Yes, it does.

Appendix B: Resume for Alice Havenar-Daughton

Alice Havenar-Daughton
Director of Customer Programs, MCE
1125 Tamalpais Ave, San Rafael, 94901

RELEVENT SKILLS AND EXPERIENCE

- Strong background in energy efficiency, with experience in program design, implementation, and evaluation.
- Oversees implementation energy programs of over $10 million annually in the Marin Clean Energy service territory.
- Oversaw program launch of MCE's first low income multifamily energy efficiency program, the LIFT Pilot Program.

EDUCATION

American University, Washington DC, *2010*
M.A. Natural Resources and Sustainable Development
McGill University, Montreal, Canada, *2005*
B.SC. Architecture

WORK EXPERIENCE

MCE San Rafael, CA, *May 2018 – present*

Director of Customer Programs

- Oversees MCE's portfolio of customer programs, including energy efficiency, transportation electrification, low income solar.
- Represents MCE externally in stakeholder forums such as CAEECC and CalTF, and through speaking engagements.
- Lead the development of a new program data tracking tool to provide greater insights into program performance and streamline reporting

MCE San Rafael, CA, *June 2017 – April 2018*

Manager of Policy and Planning, Customer Programs

- Oversees for planning for Demand Side Resource Pilot Programs, including, electric vehicles, fuel switching and low-income solar.
- Works collaboratively with the Regulatory Team to develop the strategy for MCE's engagement with the CPUC in the Business Plan Application process, including developing content for filings, drafting talking points, engaging with partners and

serving as MCE's representative to the CAEECC.

- Manages MCE's EM&V budget for Energy Efficiency Programs and LIFT.
- Oversees all Energy Efficiency and LIFT program reporting to the CPUC.
- Manages MCE's SF Seasonal Savings Program, the CEC BEO Grant and grant compliance for the electric vehicle charges owned by MCE.

MCE San Rafael, CA, *October 2015 – June 2017*

Energy Efficiency Program Manager

- Managed MCE's Single-Family Energy Efficiency Program. Oversaw the transition of the MCE Energy Efficiency Webtool to the Statewide Marketing, Education & Outreach Program. Ended an unsuccessful behavior program and launched a smart thermostat pilot program that more than quadrupled the savings to MCE customers.
- Managed all energy efficiency program reporting to the California Public Utilities Commission. Transferred quarterly reporting to external consultant which resulted in efficiencies for implementers and improved accuracy of reporting.
- Supported MCE's Business Plan Application through sector chapter development, managing cost effectiveness work done by consultants and leading the internal program logic model and metrics development.
- Represented MCE through engagement and comments on several CPUC-funded EM&V studies of MCE's programs.

MCE San Rafael, CA, *July 2014 – October 2015*

Energy Efficiency Specialist

- Developed tracking systems for MCE's Energy Efficiency program expenditures and savings. Worked with Maher Accountancy to ensure that expenditures were tracked in a way that supported our reporting obligations to the CPUC.
- Represented MCE at the Reporting Program Coordination Group at the CPUC.
- Tracked data and prepared monthly, quarterly and annual reports for the CPUC. Provided data necessary for other compliance requirements.

Opinion Dynamics Corporation Oakland, CA, *November 2010 – July 2015*

Senior Analyst

- Served as a lead analyst on process and impact evaluations of energy efficiency and demand response programs in California and across the county. Programs evaluated in California include the Statewide Emerging Technologies Program, the Statewide Marketing Education and Outreach Program, PG&E Commercial Time of Use Rate Pilot. Projects outside of California included evaluations of a Massachusetts-based Small Business Direct Install Program, a Multifamily Program in Illinois, a HVAC program in Arizona and technical consulting on the development of the Illinois

- technical reference manual.
- Managed call center staff and junior analysts conducting market research surveys and interviews. Represented the company through in person presentations of findings and recommendations.

Alliance for Climate Protection Washington DC, *May 2010 – September 2010*

Solutions/Policy Team Fellowship

- Analyzed national climate and energy legislation to support renewable energy advocacy effort.

American Council for an Energy Efficient Economy (ACEEE) Washington DC, *January 2010 – April 2010*

Buildings Team Intern

- Conducted research on barriers to energy efficiency in building codes.

Energetica Cochabamba, Bolivia, *August 2008 – May 2009*

Research Assistant

- Conducted a study on the potential for solar water heaters in urban areas of Bolivia which supported the initiation of a new solar water heater project, Proyecto ElSol.
- Assisted in rural educational workshops for subsidized solar panel recipients.

Appendix C: Letters of Support

ANNA M. ROTH RN, MS, MPH
HEALTH SERVICES DIRECTOR

DAN PEDDYCORD, RN, MPA/HA
DIRECTOR OF PUBLIC HEALTH

CONTRA COSTA
HEALTH SERVICES

Contra Costa
Public Health

597 Center Avenue, Suite 200
Martinez, California 94553
Ph 925-313-6712
Fax 925-313-6721
DANIEL.PEDDYCORD@HSD.CCCOUNTY.US

November 1, 2019

Commissioner Batjer
Commissioner Randolph
Commissioner Guzman Aceves
Commissioner Rechtschaffen
Commissioner Shiroma

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: MCE's Low-Income Families and Tenants (LIFT) 2.0 Proposal

Dear Commissioners:

Contra Costa Health Services strongly supports Marin Clean Energy's (MCE's) proposed Low Income Families and Tenants (LIFT) 2.0 pilot program. MCE's innovative program design addresses a number of important issues, including increasing access to low income energy efficiency programs within underserved and hard-to-reach communities. MCE's program is designed to deliver high impact measures that will benefit health, safety and comfort of low-income households while saving energy and lowering utility bills.

LIFT 2.0 places an emphasis on reaching some of the most vulnerable residents of low-income multifamily properties in MCE's service territory, including, but not limited to, residents aging in place and those living in buildings with high incidence of asthma.

Contra Costa Health Services is an integrated Health Services provider serving residents of Contra Costa County, especially low-income residents, with health insurance, hospital and ambulatory care, and Public Health services. Contra Costa Health Services recently developed a business plan model with MCE and the County's Energy Efficiency program to conduct asthma in-home trigger assessments and remediation in coordination with energy efficiency assessments. We are actively working together to implement and identify stable sources of funding for this program.

Contra Costa Health Services strongly urges you to approve MCE's proposed LIFT 2.0 pilot program which provides enhanced, equitable access to energy resources for low income residents in multifamily buildings.

Sincerely,

Michael Kent

Michael Kent
Hazardous Materials Ombudsman
Contra Costa Health Services

Green & Healthy Homes Initiative®

2714 Hudson Street
Baltimore, MD 21224-4716
P: 410-534-6447
F: 410-534-6475
www.ghhi.org

October 21, 2019

Commissioner Marybel Batjer
Commissioner Liane M. Randolph
Commissioner Martha Guzman Aceves
Commissioner Clifford Rechtschaffen
Commissioner Genevieve Shiroma
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: MCE's Low-Income Families and Tenants (LIFT) 2.0 Proposal

Dear Commissioners,

The Green & Healthy Homes Initiative strongly supports Marin Clean Energy's (MCE's) proposed Low Income Families and Tenants (LIFT) 2.0 pilot program. MCE's innovative program design addresses a number of important issues, including increasing access to low income energy efficiency programs within underserved and hard-to-reach communities. MCE's program is designed to deliver high impact measures that will benefit health, safety and comfort of low-income households while saving energy and lowering utility bills.

LIFT 2.0 places an emphasis on reaching some of the most vulnerable residents of low-income multifamily properties in MCE's service territory, including, but not limited to, residents aging in place and those living in buildings with high incidence of asthma.

GHHI has supported MCE's GHHI Marin since the pilot program launched in 2016. This is one of over 30 GHHI sites across the country, each committed to aligning, braiding, and coordinating funding and resources towards improving housing quality for low-income families. Through this initiative, the LIFT program funds will be leveraged with additional dollars and resources, increasing the ability to achieve a whole-building approach to energy efficiency and health. Recently, GHHI has also supported MCE's collaborative effort with Contra Costa Health Services to develop a home-based asthma program, which would further LIFT's ability to allocate its resources towards those who need it the most.

GHHI strongly urges you to approve MCE's proposed LIFT 2.0 pilot program which provides enhanced, equitable access to energy resources for low income residents in multifamily buildings.

Sincerely,

Ruth Ann Norton
President & CEO

THE GREENLINING INSTITUTE
360 14TH STREET, 2ND FLOOR
OAKLAND, CA 94612
GREENLINING.ORG

October 31, 2019

Commissioner Batjer
Commissioner Randolph
Commissioner Guzman Aceves
Commissioner Rechtschaffen
Commissioner Shiroma
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: MCE's Low-Income Families and Tenants (LIFT) 2.0 Proposal

Dear Commissioners,

The Greenlining Institute strongly supports Marin Clean Energy's (MCE's) proposed Low Income Families and Tenants (LIFT) 2.0 pilot program. MCE's innovative program design addresses a number of important issues, including increasing access to low income energy efficiency programs within underserved and hard-to-reach communities. MCE's program is designed to deliver high impact measures that will benefit health, safety and comfort of low-income households while saving energy and lowering utility bills.

LIFT 2.0 emphasizes reaching some of the most vulnerable residents of low-income multifamily properties in MCE's service territory, including, but not limited to, residents aging in place as well as those living in buildings with high incidence of asthma. The program is also expanding low income energy efficiency programs to eligible tenants in naturally occurring affordable housing that are now underserved. Finally, MCE will provide these households a more comprehensive set of measures in a streamlined manner by leveraging its own existing energy efficiency program as well as coordinating directly with other available low-income energy programs.

The Greenlining Institute looks forward to engaging both officially and unofficially in reviewing the impacts of MCE's LIFT 1.0 pilot program, to determine the pilot program's ability to truly deliver services for vulnerable low-income customers and the overall goals of the ESAP program. Greenlining will engage in the proceeding to assess the success of MCE's implementation strategies used for LIFT 1.0 and to offer recommendations to guide LIFT 2.0. Greenlining therefore strongly urges you to approve MCE's proposed LIFT 2.0 pilot program which provides enhanced, equitable access to energy resources for low income residents in multifamily buildings.

Sincerely,
Lisa Hu
Energy Equity Program Manager
The Greenlining Institute

SIERRA CLUB
SAN FRANCISCO BAY

Serving Alameda, Contra Costa, Marin and San Francisco counties

November 1, 2019

Commissioner Batjer
Commissioner Randolph
Commissioner Guzman Aceves
Commissioner Rechtschaffen
Commissioner Shiroma

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: MCE's Low-Income Families and Tenants (LIFT) 2.0 Proposal

Dear Commissioners,

Sierra Club strongly supports Marin Clean Energy's (MCE's) proposed Low Income Families and Tenants (LIFT) 2.0 pilot program. MCE's innovative program design addresses a number of important issues, including increasing access to low income energy efficiency programs within underserved and hard-to-reach communities. MCE's program is designed to deliver high impact measures that will benefit health, safety and comfort of low-income households while saving energy and lowering utility bills.

LIFT 2.0 places an emphasis on reaching some of the most vulnerable residents of low-income multifamily properties in MCE's service territory, including, but not limited to, residents aging in place as well as those living in buildings with high incidence of asthma. The program is also expanding low income energy efficiency programs to eligible tenants in naturally occurring affordable housing that are now underserved. Finally, MCE will provide these households a more comprehensive set of measures in a streamlined manner by leveraging its own existing energy efficiency program as well as coordinating directly with other available low-income energy programs.

Additionally, California is experiencing an increasing occurrence of extreme heat waves, with practically each summer breaking previously held record temperatures. Many Northern California residents -- particularly low-income families -- do not have air conditioning and are not prepared to adapt to these heat waves, posing new health and safety risks. Promoting heat pump air conditioning is an added bonus as we can replace gas furnaces with electric heat pump space heaters. The heat pumps can operate in reverse and provide high efficiency cooling when needed. Electrification offers greater comfort, safety, and climate resiliency when temperatures peak.

Sierra Club strongly urges you to approve MCE's proposed LIFT 2.0 pilot program which provides enhanced, equitable access to energy resources for low income residents in multifamily buildings.

Sincerely,

Igor Tregub

Sierra Club, SF Bay Chapter Chair

DECEMBER FILINGS

December 10, 2019

California Energy Commission
Docket Unit, MS-4
Re: Docket No. 16-OIR-05
1516 Ninth Street
Sacramento, CA 95814-5512

CalCCA Comments on the Revised Modifications of Regulations Governing the Power Source Disclosure Program (AB 1110)

CalCCA respectfully submits the following comments to the California Energy Commission regarding the 15-Day Language on Modifications of Regulations Governing the Power Source Disclosure Program, issued November 25, 2019.

CalCCA appreciates the Commission's efforts to further refine and clarify the proposed regulations. However, an important issue must be addressed before the regulations are adopted. **An amendment to the specified purchase definition is necessary to ensure CCA customers can claim the benefits of nuclear and large hydroelectric resources they've already paid for through the Power Charge Indifference Adjustment ("PCIA") mechanism in 2019 and 2020.** CalCCA also seeks a minor clarification to the double-counting provision for large hydroelectric and nuclear resources.

2019 and 2020 Benefits

Many customers that are no longer taking retail electric service from investor-owned utilities ("IOUs") continue to pay for the costs of GHG-free large hydroelectric and nuclear resources through a California Public Utilities Commission ("CPUC")-approved ratemaking mechanism – the PCIA. While customers currently pay for the above-market costs of these resources, there is currently no mechanism to ensure that the emissions reduction *benefits* also accrue to CCA customers. The CPUC is in the process of adopting such a mechanism ("CPUC-approved mechanism"), but it will not be in place until later in 2020. In light of the timeline for CPUC action, several CCAs and Pacific Gas and Electric ("PG&E") are jointly developing an interim solution for 2019 and 2020 through the advice letter process at the CPUC,[1] but the interim solution is contingent upon CEC action.

As CalCCA stated in its comments on the modified regulations issued in September 2019, the definition of "specified purchase" must be amended to allow, for 2019 and 2020[2] only, purchases to be documented after generation of the electricity.[3] Aside from a requirement that agreements

[1] PG&E Advice Letter 5705-E dated December 2, 2019.
[2] The transactions are expected to commence in Q2 of 2020, though that timing may shift. Once the allocations commence, all subsequent allocations would take place prior to generation of the electricity.
[3] CalCCA's proposed change to the 15-Day Language is in italics: For facilities not owned by the retail supplier, specified purchases shall be documented through agreements executed prior to generation of the procured

be executed prior to the generation of electricity, the transactions through the CPUC-approved mechanism conform in every other way with the "specified purchases" definition: they represent electricity from an auditable contract trail, traceable to specific generating facilities located within California. The transactions are also intentional purchases, since the purchasing retail supplier must affirmatively elect to accept the trade.

Absent CEC action to modify the "specified purchase" definition, the GHG-free resources contemplated for trade will remain with PG&E for Power Content Label reporting purposes in 2019 and 2020.[4] This creates a frustrating asymmetry, where PG&E may claim all environmental attributes associated with these resources, despite CCAs' demonstrated interest in transacting for them.

CalCCA requests a very narrow change to the regulations to accommodate what is ultimately a timing issue. Indeed, had the PCIA discussions proceeded on a faster timescale, this request to the CEC would not be necessary.

Double-counting Provision Clarification

CalCCA seeks a minor clarification to the double counting provision for nuclear and large hydroelectric procurement in Section 1393(7) of the draft regulations. This change makes it clear that the party trading the attributes away cannot classify the procurement as specified. In doing so, it clarifies that the attributes and energy can be traded, and the receiving party can classify those resources as specified. The proposed change is below (*added language italicized*):

> (7) Procurements from nuclear or large hydroelectric generating units cannot be classified as specified purchases *by one party* if the associated environmental attributes have been claimed by, or traded to, a separate party.

CalCCA appreciates the Commission's attention to this matter and looks forward to continuing to work with the Commission to achieve the goals of AB 1110.

Sincerely,

Irene Moosen
Director of Regulatory Affairs
California Community Choice Association
(415) 587-7343 | irene@cal-cca.org

---

electricity, *except that purchases of generation from in-state or dynamically scheduled large hydroelectric and nuclear resources in 2019 and 2020 may be documented after the generation of the electricity when a retail supplier whose customers are paying for such resources through the California Public Utilities Commission approved Power Charge Indifference Adjustment elects to purchase such in-state large hydroelectric or nuclear resources following a CPUC-approval of a mechanism for allocating such resources.*

[4] See PG&E Advice Letter 5705-E at p. 4.

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

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION
COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING
SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PORTFOLIO
AND RELATED POLICY ACTIONS**

Irene K. Moosen
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
415.587.7343
regulatory@cal-cca.org

Director, Regulatory Affairs
California Community Choice Association

Evelyn Kahl
Ann Springgate
Benjamin Ellis
Buchalter, A Professional Corporation
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
ekahl@buchalter.com

Counsel to the California Community Choice Association

December 17, 2019

TABLE OF CONTENTS

TABLE OF ACRONYMS

CalCCA	California Community Choice Association
CAISO	California Independent System Operator
CEC	California Energy Commission
CCA	Community Choice Aggregator
CCGT	Combined Cycle Generation Turbine
DAM	Day Ahead Market
DCPP	Diablo Canyon Power Plant
ELCC	Effective Load Carrying Capability
EO	Energy Only
FCDS	Full Capacity Deliverability Status
FOM	Front of the Meter
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt Hour
HASP	Hour Ahead Scheduling Process
IOU	Investor Owned Utility
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
LCR	Local Capacity Requirement
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MMT	Million Metric Tons
MW	Megawatt
MWh	Megawatt Hour
O&M	Operations and Maintenance
OOS	Out-of-State
OTC	Once Through Cooling
PCM	Production Cost Modeling
PSP	Preferred System Portfolio
RA	Resource Adequacy
RSP	Reference System Portfolio
RTM	Real Time Market
SCE	Southern California Edison Company
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
TPP	Transmission Planning Process
WECC	Western Electricity Coordinating Council

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

1. The Reference System Portfolio does not "over-rely" on solar and storage resources given current expectations of technology performance and associated modeling results over a range of modeling scenarios. However, future IRP cycles should revisit this concern as more experience is gained with these technologies on the scale conceived in the RSP. This uncertainty highlights the need for the Commission to avoid directives that risk imposing unnecessary stranded investment costs on customers. **Solar Reliance** **Storage Reliance**

2. Assessing criteria pollutant impacts of fossil resources, considering the rate of criteria pollution (*e.g.,* grams per megawatt-hour), gross production of criteria pollution (*e.g.,* kilograms), and damage to human health in populated zones (*e.g.,* Disability Adjusted Life Years), in modeling will facilitate prudent decision-making regarding the "least regrets" thermal generation to be retained for reliability as California transitions toward a fully decarbonized grid. **Thermal Generation** **Criteria Pollutant Metrics**

3. While import availability may decline over time, as coal plants in the West retire and other states implement increasing levels of renewable portfolio standards, the static import constraints in SERVM and RESOLVE do not accurately reflect California's near-term or perhaps mid-term realities. The SERVM model assumptions reflect the planned WECC resource retirements, yet do not identify reliability shortfalls unless the artificial import constraints are applied. Staff should thus remove these constraints or develop a trendline showing a decline in availability over the planning horizons recognizing the timing of WECC-wide retirements and increases in carbon-free procurement. **Import Assumptions**

4. If, after adjusting for more realistic levels of imports, a need for additional "generic effective" capacity remains to meet a loss of load expectation of less than 0.1, Staff should test various resource- and location-specific solutions (*e.g.*, longer duration batteries) to better understand the quantity and type of need, rather than assuming a lump sum of generic capacity. **Generic Effective Capacity**

5. To target better solutions requires greater accuracy in busbar mapping, which should be prioritized in this proceeding and subject to additional stakeholder input. **Busbar Mapping**

6. The accuracy of the baseline resource assumptions could be improved by: (1) adding all new build resources contracted by all load-serving entities; (2) expanding coordination with other WECC-wide regulatory agencies to understand resource retirements and load forecasts to inform market interactions; and, (3) vary assumptions for storage duration from the current assumption of 1,479 MW of four-hour duration battery storage by 2030. **Baseline Resources Assumption**

7. A CalCCA sensitivity case shows that assuming longer duration storage in the near-term

reduces the duration of incremental storage resources, especially in years 2022 and 2026. Sensitivity cases should be added to the IRP modeling to identify an appropriate mix of battery configurations for system needs, including at least a subset of battery storage capacity needs to have an eight- to nine-hour duration. **Battery Storage Duration**

8. SERVM should isolate Diablo Canyon Power Plant impacts on reliability needs using an "in/out" methodology to identify any system resource adequacy deficiency that should be allocated to all load-serving entities within the three Transmission Access Charge areas in proportion to their load ratio share. **Diablo Canyon Impacts**

9. The Commission should replace SERVM, for the next IRP cycle, with a production cost model that models security-constrained unit commitment and security-constrained economic dispatch (*e.g.,* PLEXOS, GridView, UPLAN, GE MAPS, Power System Optimizer (PSO), or AURORA). **Production Cost Modeling**

10. The 46 MMT Alternate Scenario should be used for reliability and policy-driven bases cases for the next CAISO Transmission Planning Process, provided a robust feedback loop is established between the IRP and the TPP that includes stakeholder feedback on the busbar mapping process. **CAISO TPP Base Case**

11. Greater flexibility in the aggregation process for the 2020 Preferred System Portfolio to allow load-serving entities to better reflect individual policy and legal drivers and to incorporate more current and granular data will improve the accuracy and reliability of the IRP outcome. **Plan Aggregation**

12. The Commission should not rely on these comments to make decisions about resource development (*e.g.,* **geothermal** or **pumped storage**) or **transmission** development, but should limit the use of the comments to refining its modeling assumptions, base cases and other related matters. The need for extraordinary resource development, if considered at all, should be taken up as the Commission considers the adoption of a Preferred System Portfolio.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PORTFOLIO

The California Community Choice Association[1] submits these Comments in response to the *Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio* issued on November 6, 2019 (Ruling).

I. INTRODUCTION

CalCCA appreciates the great strides made by Commission staff in advancing IRP modeling between the 2017-2018 Reference System Plan and the 2019-2020 Reference System Plan. These advances, supported by additional adjustments as this Integrated Resource Planning process advances, will increase the likelihood of California's success in decarbonizing the grid while maintaining reliability. Despite these advances, however, some level of uncertainty in the IRP process is inevitable. These comments identify several factors that give rise to uncertainty—length of planning horizons, pace of decarbonization, levels of available imports, and accuracy of busbar mapping—and encourage the Commission to manage these issues in a

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

way that promotes the accuracy and reliability of the IRP outcomes and procurement flexibility over the long run.

The *planning horizon* will materially affect the level of uncertainty in the IRP output. Near-term estimates of capacity expansion resource needs can be modeled with some degree of confidence, but technological innovation, resource availability, and project economics are likely to shift dramatically throughout the 2020s, leaving little certainty regarding the precise portfolio mix required in the mid- and long-term. Thus, as the Commission moves forward in the IRP process, the identification of resource portfolios will become firmer. For example, a strong indication that LSEs will rely on OOS wind resources, taking into consideration the cost of the resulting new transmission infrastructure, may justify the need for including those resources in the default (base) portfolio. Set in this light, the significant capacity of solar and Li-Ion battery storage included in the RSP does not necessarily equate to "overreliance" in the mid- to long-term. Any conclusions drawn from this IRP cycle must recognize planning horizon uncertainty and accommodate changes in resource mix over time.

The unprecedented *pace of decarbonization* further raises the level of uncertainty. The transition to a fully decarbonized grid will require revision and course-correction throughout the process to address technical and economic realities that arise along the path. In modeling this transition, particular attention should be given to what portion of the existing gas-fired generation fleet should be retained or retired within the IRP planning horizons. Using criteria pollutant levels as a metric, as CalCCA has proposed, provides greater granularity on the impacts of these resources in making this calculation. Retention of a simple cycle turbine will have materially different impacts than the retention of a CCGT, and retention of a high capacity factor CCGT will have materially different impacts from retention of a low capacity factor unit.

Retention of some amount of thermal generation may be appropriate to mitigate threats to reliability as the state gains better experience with existing technologies and develops new technologies to reduce reliance on thermal generation. The IRP process should enable LSEs to plan carefully for swift and orderly decarbonization with attention to ensuring a thoughtful and robust approach, enabling resources put into place to operate as planned, and avoid risky and expensive investments.

The uncertainty surrounding the *level of available imports* further complicates the IRP process. However, the RSP's 5 GW constraint on imports for all hours in economic dispatch of the model, which produces a need for 2,000 MW of "perfect" capacity, is counterproductive. Exacerbating the problem, Staff's newly proposed approach, presented on November 4, 2019, constrains imports not only for RA purposes, but also for energy deliveries.[2] Given the changes occurring in WECC, including the retirements of coal plants and other states establishing renewable portfolio standards, the Commission needs to identify realistic levels of both RA and energy imports and ensure that these accurate levels are reflected in the WECC-wide unit commitment and dispatch modeled in SERVM.[3] It is CalCCA's understanding that the SERVM model used by Energy Division in this proceeding does, in fact, already reflect significant

---

2 *See ALJ Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (Ruling Seeking Comment), Nov. 6, 2019, at 16; *see also IRP Modeling Advisory Group Webinar: 2019-20 IRP Proposed Reference System Plan* (IRP Webinar), Nov. 6, 2019, at 29.

3 CalCCA has raised the need for a more detailed assessment numerous times. *See Opening Comments of California Community Choice Association on Assigned Commissioner and Administrative Law Judge Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues* at 13-15 (CalCCA Reply Comments); *see also Reply Comments of California Community Choice Association on Assigned Commissioner and Administrative Law Judge Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues* at 3-18 (CalCCA Opening Comments); *Comments of California Community Choice Association on Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* (CalCCA PD Comments) at 3-6; *Amended Reply Comments of California Community Choice Association on Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* (CalCCA PD Reply Comments) at 2-3.

WECC-wide resource retirements, so artificial constraints on imports should not be needed unless expected retirements change. If, however, a need for 2,000 MW of generic resources exists, the Commission must identify resource- and location-specific solutions (*e.g.*, longer duration batteries) rather than assuming a lump sum of effective capacity. Providing greater clarity of what resources are needed, when, and where will give the state's LSEs far greater direction in developing those resources. Failing to do so will almost certainly result in a transmission grid that will not meet the needs of the energy portfolio.[4]

To target effective solutions requires *more accurate busbar mapping.* The Ruling proposes to have the busbar mapping process proceed on a parallel path with the adoption of the RSP. The busbar mapping process needs to improve in three primary areas to be better integrate into the IRP process.

- More frequent data and information sharing among the Commission, CEC and the CAISO is necessary to establish a more effective and timely feedback loop within the same planning cycle.
- Stakeholders need to have an opportunity to provide meaningful feedback into the busbar mapping process rather than having the decisions made administratively.
- The Commission needs to utilize the most updated information available from the CEC and CAISO assessments into the busbar mapping process as it becomes available. CalCCA has included some examples of such assessments in its response to Q. 12, Q. 19 and Q.20.

CalCCA has also offered informal comments on busbar mapping and looks forward to providing further input to improve the IRP outcome.

Finally, *the need to accommodate LSE-specific plans* into a systemwide planning exercise indisputably adds a layer of complexity, but one which has the potential to increase the accuracy

---

[4] *See Notice of Ex Parte Communication by the California Independent System Operator Corporation* (CAISO Ex Parte), Nov. 27, 2019, located at http://www.caiso.com/Documents/Nov27-2019-Notice-ExParteCommunication-IntegratedResourcePlanning-R16-02-007.pdf.

and reliability of the IRP outcome. Advances in IRP modeling and the learning afforded all stakeholders in the last IRP cycle will enable better alignment of the RSP and the plans of individual LSEs. Full alignment may be unrealistic, however; the least-cost, best-fit resources for individual CCAs may deviate from the RSP due to differences in anticipated demand profiles, existing portfolios, local environmental and economic development preferences, or other factors. Full alignment may also be undesirable as many LSEs have more aggressive decarbonization targets than statewide goals—the Commission should not hold back those LSEs innovating faster and should not take statewide goals as a ceiling rather than a floor. Understanding and modeling these differences offers an opportunity to advance the accuracy of the IRP outcome and may stimulate a greater range of possible solutions. The Commission should provide greater flexibility in the aggregation process for the 2020 Preferred System Portfolio and accommodate LSE-specific conditions where reasonable, requiring qualitative and quantitative support from LSEs presenting deviations.

The Commission, the IOUs, ESPs and CCAs share common objectives: maximizing the pace of decarbonization while maintaining system reliability. Aware of the challenges, and committed to fact-based and collaborative assessment, CalCCA looks forward to working with the Commission and other stakeholders to advance these objectives.

A. The IRP Process Should Avoid the Need for Urgent and Unanticipated Procurement Directives

The Assigned Commissioner and Administrative Law Judge issued an unanticipated ruling on June 20, 2019, to address the perceived inadequacy of procurement to meet system RA requirements in 2021-2023.[5] The June 2019 Ruling was issued less than two months after the

[5] *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues,* June 20, 2019 (June 2019 Ruling).

decision adopting the PSP for the 2017-2018 IRP cycle, which included four study years: 2018, 2022, 2026 and 2030.[6] Moreover, rather than relying on the IRP models—RESOLVE and SERVM—Energy Division Staff signaled the need for additional procurement relying on a "stack" analysis, which compared an inventory of available resources to the IEPR demand forecast.[7]

The Commission appears to have addressed obvious causes of the unexpected procurement track directive in this IRP cycle. One explanation could lie in the focus of the IRP on meeting carbon reduction goals, as required by Senate Bill 350, rather than specifically to ensure reliability. Another potential driver was the limited scope of LOLE analysis, conducted only for 2030 but not for 2022 and 2026—the other study years.[8] This shortcoming has been addressed fully in the 2019-2020 cycle. The treatment of imports also created a gap. Staff's stack analysis assumed only around 5 GW of imports, while the PSP assumed approximately 11 GW. Additional imports beyond 5 GW might be plausible and realistic, as discussed in response to Questions 8 and 9, and the Commission should coordinate with entities external to the CAISO balancing authority area to obtain a better estimate of the underlying loads and resources that will affect available imports in the future. Finally, the devalued ELCC for solar and wind resources also contributed to the shift between the 2017-2018 IRP and the procurement track directive. The underlying drivers of this ELCC shift (primarily shifting evening peak) are captured explicitly in the SERVM analysis that is now performed for interim model years.

The Commission should take direct aim at ensuring that the IRP prevents unanticipated, urgent directives in the future, thereby enabling LSEs to undertake a thoughtful and deliberate

---

6 Decision (D.) 19-04-040 at 19.
7 June 2019 Ruling at 7-13.
8 *Decision Requiring Electric System Reliability Procurement for 2021-2023,* Rulemaking (R.) 16-02-007, Sept. 12, 2019, at 13-14.

procurement strategy. The Commission should seek comments from LSEs and other affected parties to identify any additional drivers for the procurement track to avoid creating similar conditions in the 2019-2020 IRP cycle. CalCCA looks forward to working productively with the Commission to develop approaches to ensure orderly planning in the future.

II. RESPONSES TO QUESTIONS POSED BY RULING

A. Modeling and Analysis

1. Please provide any comments on the use of the RESOLVE model.

RESOLVE is a capacity expansion model that co-optimizes investment and dispatch for a selected set of days of a multi-year horizon, in order to identify least-cost portfolios for meeting specified greenhouse gas targets. RESOLVE has been effective in providing a very high-level assessment of identifying resource mix in the outer years based upon meeting the economic and climate change policy objectives. The tool's availability in the public domain allows stakeholders to perform their own independent analyses that can be compared with the CPUC staff modeling efforts. As the market evolves, however, changes must be considered.

CalCCA appreciates Staff's efforts to improve the RESOLVE methodology, refine input assumptions, and calibrate the RESOLVE model with SERVM. In particular, CalCCA supports several refinements evidenced in the RSP:

- ✓ Updated levelized cost for different renewable and preferred resources including battery storage;
- ✓ New economic retention functionality to examine what portion of the existing gas-fired generation fleet should be retained or retired within the IRP planning horizon;
- ✓ Identification of procurement and type of renewable and integration resources including solar, battery storage, pumped storage, shed demand response and geothermal in a manner that can further minimize the need for retention of fossil resources;
- ✓ Allowing RESOLVE to build new transmission for 3 GW of out-of-state wind resources as a default assumption;

- ✓ Staff proposal on busbar mapping methodology for IRP portfolios includes stakeholder feedback opportunities to facilitate a better feedback loop between the CPUC IRP and CAISO TPP; and,
- ✓ Updated RESOLVE model that more fully represents "nested" transmission constraint limits and associated transmission costs.

Despite these refinements, RESOLVE continues to offer an incomplete representation in several respects. The model's representation of generation and transmission system has been simplified, preventing a full network understanding of procurement implications. In addition, it lacks adequate technological, temporal (*e.g.,* interday and seasonable energy needs) and geographical granularity for the resources it incorporates. These drawbacks create a level of uncertainty in the model outputs.

RESOLVE's effectiveness as a tool to advance decarbonization could be improved by incorporating additional configurations and attributes. To improve the model's flexibility and the suitability of its outputs, it should be modified to:

- ✓ Model multiple battery configurations and local solar options, particularly given the likelihood that hybrid solar/storage projects will be used increasingly to meet decarbonization goals;
- ✓ Incorporate criteria pollution considerations, recognizing their importance in addressing disadvantaged community concerns;
- ✓ Better incorporate in-front-of-the-meter distribution-connected resources as a distinct resource class with different cost characteristics than behind-the-meter resources; and,
- ✓ Include out-of-state wind transmission development.

These changes will enhance the output from RESOLVE, but may warrant some degree of additional model run time that may result from adding these attributes.

2. Provide any comments on the use of SERVM

The role of SERVM is to validate the reliability, operability, and emissions of resource portfolios generated by RESOLVE. SERVM is designed to inform security-constrained planning, meaning the primary objective is to reduce the risk of insufficient generation to an acceptable level. CalCCA appreciates Staff's efforts to improve the SERVM methodology, refine input assumptions and calibrate the model with RESOLVE. The model warrants further refinement, however, to improve the reliability of its output.

The SERVM model analyzes the capabilities of an electric system during a variety of conditions under thousands of different Scenarios and is thus better-suited than RESOLVE for system-reliability planning. Because it lacks transmission network representation, however, the model cannot capture the locational aspect of the effectiveness of generating resources. In particular, SERVM cannot capture the locational effectiveness of different types of generating resources in addressing local reliability needs. In addition, it fails to capture unit commitment constraints and transmission power flows.

Staff has improved the modeling process by calibrating RESOLVE and SERVM iteratively, by developing portfolios in RESOLVE, feeding the portfolios into SERVM, and then validating the key operational results, including GHG emissions, curtailment results, and dispatch patterns. This exercise has helped the stakeholders who do not have access to independently evaluate SERVM in vetting the output of RESOLVE and SERVM alike.

To improve the analytical process and usefulness of model output in the next cycle, CalCCA proposes that the Commission replace the model with a production cost model that models security constrained unit commitment and security constrained economic dispatch SCED. The commercially available production cost models that could be deployed include PLEXOS, GridView, UPLAN, GE MAPS, Power System Optimizer (PSO), AURORA, etc. If any of these models can be used in a parallel processing mode then it would be very helpful to run hundreds of scenarios in a timely fashion. Without these functionalities, it is impossible to determine location and effectiveness. Indeed, the CAISO uses SCUC and SCED to perform unit commitment and economic dispatch in its day-ahead market, hour ahead scheduling process, and real-time market. By updating the Commission's approach, IRP modeling will more closely align with the operations in the CAISO balancing authority area.

3. Provide any comments on baseline assumptions

The Integrated Resources Planning modeling relies on a set of baseline resources that can be predicted with relative confidence. The baseline includes:

- Existing resources, net of planned retirements;
- New resources that are sufficiently likely to be constructed, usually because they are owned by LSEs or contracted and have already been approved by the appropriate oversight body (*e.g.*, the Commission or a local governing board); and
- Projected demand-side programs that already have approved budgets under current policy, such as energy efficiency programs or net energy metering.

The baseline makes no further qualitative judgment on the availability of these resources.

While the baseline assumptions have been refined relative to the prior IRP cycle, several additional modifications would benefit future modeling. First, the baseline should reflect committed resources from non-IOU LSEs. CCAs have signed power purchase agreements for 3,386 MW of new build renewable and storage resources in California and throughout the WECC, the majority of which are not reflected in the baseline assumptions. CalCCA supports the development of a process for non-IOU LSEs to provide updates to the Commission as resources reach specific contracting and development milestones that could be incorporated through the development of the Reference System Portfolio.

Second, the Commission should expand coordination with other WECC-wide regulatory agencies to understand resource retirements and load forecasts to inform market interactions outside of CAISO and California. Like California, other regions are experiencing significant trends in their resource supply and demand, which, while uncertain, would be beneficial to further incorporate into IRP system modeling. These market interactions could inform new resource selection, fossil retention, the need for artificial import constraints, and other critical modeling considerations and results.

Third, the Commission should examine the assumption of 1,479 MW of 4-hour duration battery storage by 2030. Where the batteries are placed and their duration are two key dimensions critical to understand in establishing the baseline. Battery storage locations carry the potential to relieve local area constraints, and duration could affect the amount of capacity required. For instance, it appears that in some LCR areas and/or sub-areas, 4-hour storage is adequate, but in some other areas like SCE's Santa Clara sub-area, 8-hour storage might be required.[9] Presumably, if the need for 8-hour vs. 4-hour storage is known in advance, procurement contracts can be structured that comply with that need. For example, instead of stacking two 4-hour battery storage units it should be more effective to add an 8-hour battery storage in the Santa Clara area. The 4-hour battery duration is an artifact of past RA rules, but recent research by the CAISO has indicated that this is not sufficient to provide reliability within some local areas. Instead of treating storage duration as an input, the models should consider how to determine the appropriate duration of storage as discussed in response to Question 8.

Other issues have recently arisen with respect to the baseline assumptions underlying Decision (D.) 19-11-016 in comments submitted by stakeholders, including duplication of resources, inaccurate accounting for retirements and other technical issues.[10] To the extent the

[9] LCR Reduction Assessment Big Creek–Ventura Area and Santa Clara Sub-area, CAISO 2019-2020 Transmission Planning Process Stakeholder Meeting, Nov. 18, 2019, at 12, located at http://www.caiso.com/Documents/Presentation-2019-2020TransmissionPlanningProcess-Nov182019.pdf.

[10] Parties submitted comments on baseline resources in R.16-02-007 on December 9, 2019.

same issues pervade the baseline resource assumptions for the RSP, changes adopted in response to recent comments.

4. Provide any comments on any other assumptions

Thermal Generation. In this new Reference System Portfolio analysis, RESOLVE allows retention of dispatchable thermal generation with the objective of minimizing the overall CAISO system costs, with the exception of planned retirements. In addition, thermal generation needed in local capacity areas is also assumed to be retained. CalCCA supports the new economic retention functionality in RESOLVE to allow a broader understanding of the potential use of these resources for renewable resource integration going forward. In addition, it appears that the CPUC has not yet performed the Thermal Retention Special Study, especially the low thermal retention study, which would assume 12.7 GW of thermal retirements by 2030.[11]

Beyond the current methodology, CalCCA supports inclusion of formal metrics for anticipated criteria pollution impacts of fossil resources classes as differentiated within the model, considering rate of criteria pollution (*e.g.,* grams per megawatt-hour), gross production of criteria pollution (*e.g.,* kilograms), and damage to human health in populated zones (*e.g.*, Disability Adjusted Life Years). While RESOLVE and SERVM's aggregation of generation facilities and geographical zones may blunt the specificity of these metrics, outputs from SERVM, such as hourly fossil demand within specific regions, could inform more detailed analysis which disaggregates fossil load and identifies specific operating units with known emissions characteristics and surrounding communities.

Renewable Resource Retirement. In addition to fossil resources, there is significant risk of the economic retirement of several thousand megawatts of existing renewable resources,

---

[11] *Administrative Law Judge's Ruling Seeking Comment On Proposed Scenarios For 2019-2020 Reference System Portfolio*, R.16-02-007, Feb. 11, 2019.

primarily geothermal, wind, and biomass resources developed under PURPA. CalCCA encourages the expansion of the economic retention module to include consideration of these resources to assess their viability and fit with system need moving forward.

B. Scenario Results

1. Provide any comments on the scenarios and sensitivities modeled

In addition to the 46 MMT Default scenario, Staff has modeled two other major GHG target scenarios—38 MMT and 30 MMT—and a 2045 Case to capture Senate Bill (SB) 100 goals. In addition, a number of sensitivity cases were run, to test the impact of changes in assumptions for certain individual variables. These included the following sensitivity cases: no new OOS transmission, low-cost OOS transmission, high-cost OOS transmission, offshore wind, high solar photovoltaic cost, extension of the solar investment tax credit, high battery cost, paired battery cost, low resource adequacy imports, high resource adequacy imports, 2045 end year, a high-load sensitivity, full OTC extension, partial OTC extension, and early shed demand response availability. CalCCA recommends enhancements of the sensitivities included in the Commission's modeling efforts.

Additional sensitivities should be added to address battery storage duration. RESOLVE restricts the battery storage duration capability to four hours which the CAISO has indicated could result in deficiencies under certain circumstances and in certain local capacity areas.[12] As a reference case, CAISO analysis in the Moorpark Sub-Area Local Capacity Alternative Study indicates a mix of battery configurations would be needed in certain areas to cover both evening and overnight loads. While this does not suggest shorter duration battery configurations lack

---

12 *See* CAISO Moorpark Sub-Area Local Capacity Alternative Study, Aug. 16, 2017, located at https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

value, CalCCA suggests utilizing the IRP to identify an appropriate mix of battery configurations for system needs. CalCCA recommends that sensitivity scenarios recognize that at least a subset of battery storage capacity needs to have an 8- to 9-hour duration.

CalCCA ran a sensitivity scenario, attached as Exhibit A, that forced the baseline utility-scale FOM storage of about 1,479 MW by 2030 to all be 7-hour battery storage as a proxy for longer duration storage capacity. The scenario shows that assuming longer duration storage in the near term reduces the duration of needed incremental storage resources, especially in years 2022 and 2026.

Although RESOLVE does not provide any locational guidance for the longer duration Li-Ion battery storage capacity, the CAISO's annual transmission planning process provides high-level guidance in terms of duration requirement for a local resource needed to reliably and adequately address the local requirements within each of the LCR areas and sub-areas. Especially as new technologies better suited to longer durations and different cost dynamics become available (*e.g.,* flow batteries, flywheels, etc.), alternative battery technologies should also be modeled as distinct classes in RESOLVE. While the CAISO may not be able to perform as detailed analysis as they performed for the Moorpark Sub-Area,[13] a combination of the more detailed information provided under the annual Local Capacity Technical studies and the LCR Reduction studies performed under the CAISO's 2018-2019[14] and 2019-2020[15] Transmission

[13] *See CAISO Moorpark Sub-Area Local Capacity Alternative Study,* Aug. 16, 2017, located at https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

[14] *Board-Approved CAISO 2018-2019 Transmission Plan*, March 29, 2019, located at http://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf.

[15] *Local Capacity Requirements Potential Reduction Study*, 2019-2020 Transmission Planning Process Stakeholder Meeting, Nov. 18, 2019, at 111-213, located at http://www.caiso.com/Documents/Presentation-2019-2020TransmissionPlanningProcess-Nov182019.pdf.

Plans should provide LSEs much-needed guidance in procuring local resources that meet the various sub-area and area LCR requirements.

Modifying storage assumptions also affects other resources. It reduces the dispatch of CCGT units, reducing the need to retain gas-fired generation. In particular, by 2030, more than 400 MW of additional gas capacity is not retained in the longer duration battery storage case relative to the 46 MMT base case. The reduced reliance on the gas-fired generation is made up of a combination of increased duration of the battery storage dispatch and increased reliance on unspecified imports. The longer duration battery storage also reduces renewable curtailments as well as exports.

In order to show the true impact, storage resources need to be selectively modeled at appropriate locations in a production-cost model with unit commitment, economic dispatch, and a detailed transmission network. To the extent the Commission retains current modeling tools for the IRP, it may be worth developing an additional analytical process to identify and overlay localized storage needs which incorporates the system level storage needs identified in the IRP process.

2. Provide any comments on the common metrics compared across cases

When analyzing the various scenarios and sensitivities, Commission staff used a common set of metrics to compare results. These metrics included the selected candidate resources, the amount of thermal generation capacity not retained, costs (including a metric for incremental total resource costs, revenue requirements, and an average rate), and total GHG emissions.

CalCCA encourages the Commission to identify more direct metrics for success in the thermal generation fleet. While thermal generation capacity not retained may be a reasonable proxy, it is just that—a proxy for direct benefits in the form of reduced emissions (GHG and criteria) and reduced costs (fixed O&M). Rather than this indirect metric, the Commission should focus on reduced emissions from gas facilities in the aggregate for GHG and reduced operations of inefficient gas facility classes in densely populated regions for criteria pollution. Similarly, on a cost basis, Commission staff should focus on RESOLVE outputs of fixed O&M costs (the metric by which facilities are retained).

CalCCA recommends consideration of criteria pollutant levels as a metric. While GHG emissions get top billing in the RESOLVE analysis, criteria pollutant levels are critical from the local perspective. This metric can provide more information on the impacts of gas generation retention; retention of a simple cycle turbine will have materially different impacts than retention of a CCGT, and retention of a high capacity factor CCGT will have materially different impacts from retention of a low capacity factor unit. Finally, using criteria pollutants as a criterion also will help pinpoint impacts on disadvantaged communities, especially when combined with geographic screens to identify localized impacts of resource siting and retirement.[16]

3. Provide any comments on the results from the major scenarios or sensitivities analyzed by Commission staff to develop the RSP recommendation

CalCCA strongly supports the choice to model the 30 MMT and 38 MMT cases, along with the express examination of the potential of OOS resources to address affordability concerns with decarbonization. As many CCAs are more aggressively driving decarbonization within strict cost constraints, this examination of these scenarios is extremely useful for innovative LSEs seeking to deliver the state's goals sooner. CalCCA also recognizes that it appears not all of the scenarios scoped in the February 11, 2019, ruling were conducted, and urges the Commission to conduct those studies to inform California's strategies for decarbonization.

[16] For an example of a methodology of combing capacity expansion modeling with geographic overlays, please see the work of The Nature Conservancy and E3 in analyzing the interaction between habitat conservation and renewable energy siting. Located at https://www.scienceforconservation.org/products/power-of-place

4. **Comment on the modifications to SERVM made by Commission staff to approximate RESOLVE's PRM constraint, which limits the amount of imports that can count towards resource adequacy. Were the changes appropriate? Why or why not?**

a. **Response to Ruling**

When Staff were preparing variations on assumptions to analyze the 46 MMT Default and Alternate Scenarios, they discovered an issue when comparing results from the RESOLVE and SERVM models. While both models include a simultaneous import constraint for the CAISO area at the maximum import capability level (approximately 11 GW), RESOLVE contains an additional constraint of 5 GW as the default assumption for imports that can be counted towards RA and meeting the planning reserve margin requirement of 15 percent. SERVM, by contrast, did not have any similar additional constraint on imports. Thus, in assessing whether the electric system was sufficiently reliable, SERVM was relying on a larger set of potential imports than RESOLVE. To further constrain SERVM to approximate RESOLVE's assumption that only 5 GW of imports can count towards resource adequacy, Staff have now added in SERVM a second CAISO simultaneous import limit of 5 GW that applies for all hours where gross electric demand is higher than the 95th percentile.

SERVM performs a WECC-wide hourly 8,760 chronological production costs analysis based on a detailed representation of loads, generation, and transmission infrastructure into the future. It is likely that when SERVM did not have this 5 GW of artificial constraint for economic dispatch purposes, it resulted in a level of additional import beyond 5 GW for some hours.

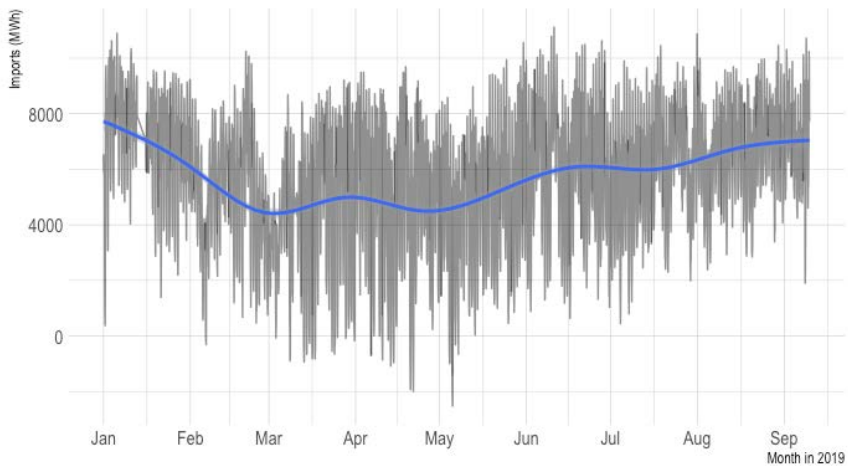
The import constraint, which is fixed throughout the modeling horizon, appears arbitrary and is inconsistent with the results of the SERVM modeling runs that reflected expected WECC-wide loads and resources. Import availability likely will tighten as coal plants retire—*conditions* *already taken into account in the SERVM model runs*. In addition, other western states will require increasing levels of balancing resources to integrate higher levels of renewables.[17] For example, while Washington is phasing out coal by 2025, Nevada's last coal plant may stay operational through 2025 or later, Oregon's coal ban takes effect in 2035, and other western states will do so later, if at all. Similarly, different states across the WECC may be implementing RPS standards in coming decades but at widely varying rates. IRP modeling must rely on something more than a general sense of these trends and an arbitrary 5,000 GW constraint, particularly when applied to energy as Staff has done.

Moreover, the 5,000 MW constraint does not reflect near-term and perhaps even mid-term realities. In 2019, imports have averaged around 6,000 MW, have exceeded 7,400 MW 25 percent of the time, and have reached slightly over 11,000 MW at their peak, as shown below.[18]

[17] CalCCA is aware of a recent study released by Energy+Environmental Economics on behalf of Rye Development, a developer of low-impact hydropower and energy storage projects in the U.S., which addresses one piece of the import puzzle: *Capacity Needs of the Pacific Northwest – 2019 to 2030*, locatd at https://www.ethree.com/wp-content/uploads/2019/12/E3-PNW-Capacity-Need-FINAL-Dec-2019.pdf. The public summaries of the study, however, lack sufficient detail to fully understand how it was developed and how to interpret its conclusions. With its Northwest focus, the analysis excludes Powerex, BP Hydro, Nevada Energy and Arizona Public Service—critical pieces of the import puzzle.

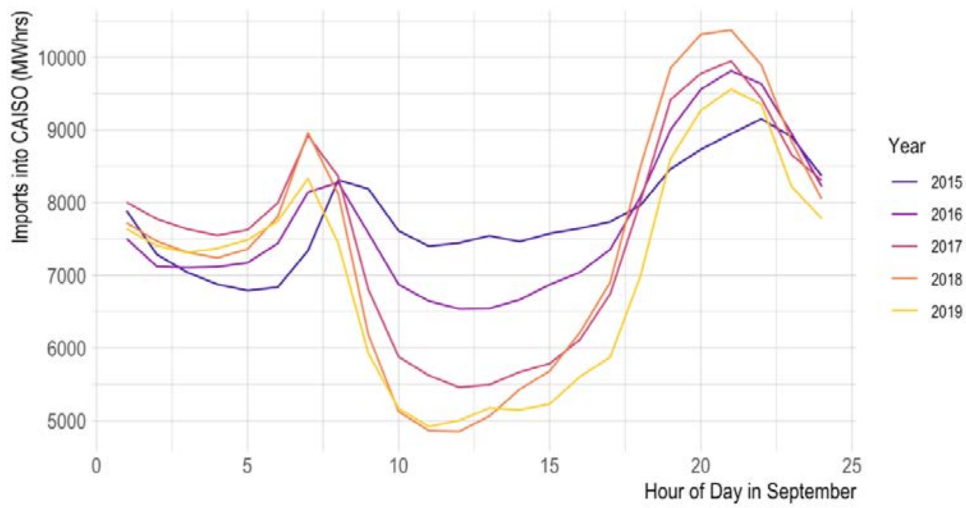
[18] This conclusion is based on data from the Energy Information Administration's Form 930, which collects self-reported CAISO intertie net-exchanges into and out of the Balancing Authority. Located at https://www.eia.gov/todayinenergy/detail.php?id=27212

Figure 1: September 2019 Exports



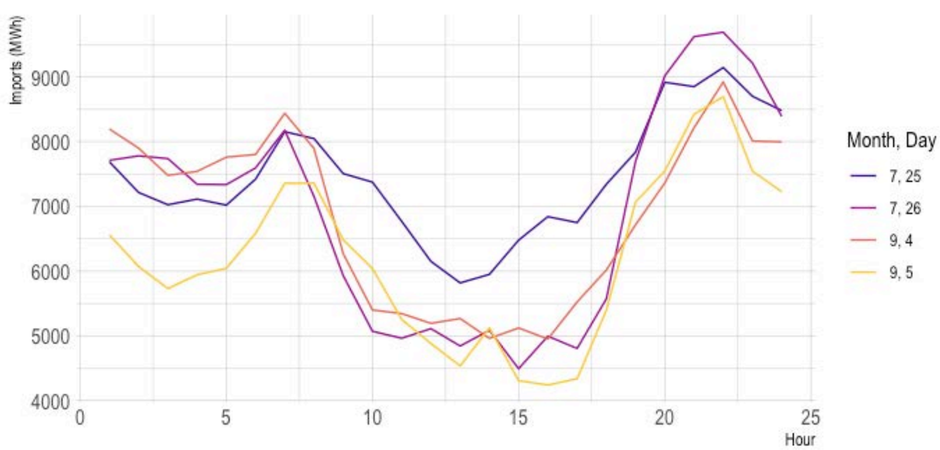
Notably, imports have been near their highest levels during September, the CAISO's 2019 peak month. The average level of imports in September was 7,583 MW, exceeding 8,668 MW 25 percent of the time and peaking at 11,113 MW. Particularly striking that import volumes in September over the past five years have tended to support the late afternoon ramp and were highest during peak and after peak hours (strongly resembling the duck curve).

Figure 2: September Imports 2015-2019



The pattern was similar for the four highest CAISO demand days in 2019, with peak imports hovering around 8,000 MW to 9,000 MW and dipping during the day when the sun shines, as shown below.

Figure 3: Imports 4 Highest CAISO Demand Days 2019



Thus, while Staff has reasonable grounds for its caution regarding import reliance, import availability should be studied more closely to assess the pace of anticipated decline before resorting to the blunt instrument of a 5,000 MW constraint for all study years. Until a study can be completed, the Commission should modify import availability sensitivities to utilize an import constraint trendline rather than a static value.

Ideally, the Commission would conduct a sensitivity analysis of imports and couple that with information from the WECC to determine the most likely trend. Given that differences in assumptions about imports drive nearly all the differences among estimates, the Commission should evaluate a range of import constraint levels, each with declining trends that reflect declining availability of existing capacity. In each of these cases, building new capacity is essentially a hedge against declining import availability. Additionally, the Commission should collect information in coordination with other entities throughout the WECC to determine the likelihood of each scenario. By modeling high, moderate, and low trends, combined with an evaluation of the likely constraint trends, the Commission should be in a position to evaluate meaningfully which scenario California should plan to hedge against.

In any event, greater coordination with planning and regulatory bodies throughout WECC to develop a more analytically robust import constraint, which considers both the shifting supply and demand throughout the planning horizon, will ensure a more accurate modeling of potential imports to California.

b. Response to Powerex

CalCCA appreciates that Powerex submitted its RSP comments on December 11, 2019, enabling a response in these comments. Powerex concludes:

> [T]he "default" and "high" assumptions related to RA imports significantly overstate the quantities of forward capacity that will remain available for contracting in the month-ahead and year-ahead System RA procurement timelines.[19]

It further concludes that the "low" scenario for RA imports of 2,000 MW is reasonable and that the "default" scenario of 5,000 MW of RA imports overstates available capacity.[20] Powerex recommends that the Commission thus "revise the 'default' scenario to include the 2,000 MW of existing long-term contractual entitlements from the 'low' scenario, plus an estimated 1,000 MW of RA imports that can be procured on a year-ahead basis, for total "default" RA imports of 3,000 MW." Powerex's analysis curiously distorts the role imports play in meeting California energy needs.

Adopting Powerex's proposal would ignore the huge amount of available import capacity and the load/resource balance of the entire WECC. Critically, Powerex fails to note that the Staff's SERVM runs modeled the fossil generation retirements included in its table. The SERVM runs used in this proceeding thus have *already* captured the tightening supply conditions in the West that Powerex describes.

In addition, Powerex highlights that "during high load conditions across the West, when short-term market prices are elevated, the CAISO BAA is often only able to secure as little as 4,000 MW of import deliveries," focusing on summer periods of 2017 and 2018. This overlooks the fact that imports were low at the time of the 2018 peak because solar and wind production was high and internal gas-fired resources were less expensive than the incremental imports. Thus, the story is not that only 4,100 MW were *available* during those periods; to the contrary, only 4,100 MW of imports were *needed* for those intervals. The chart below shows that by 7

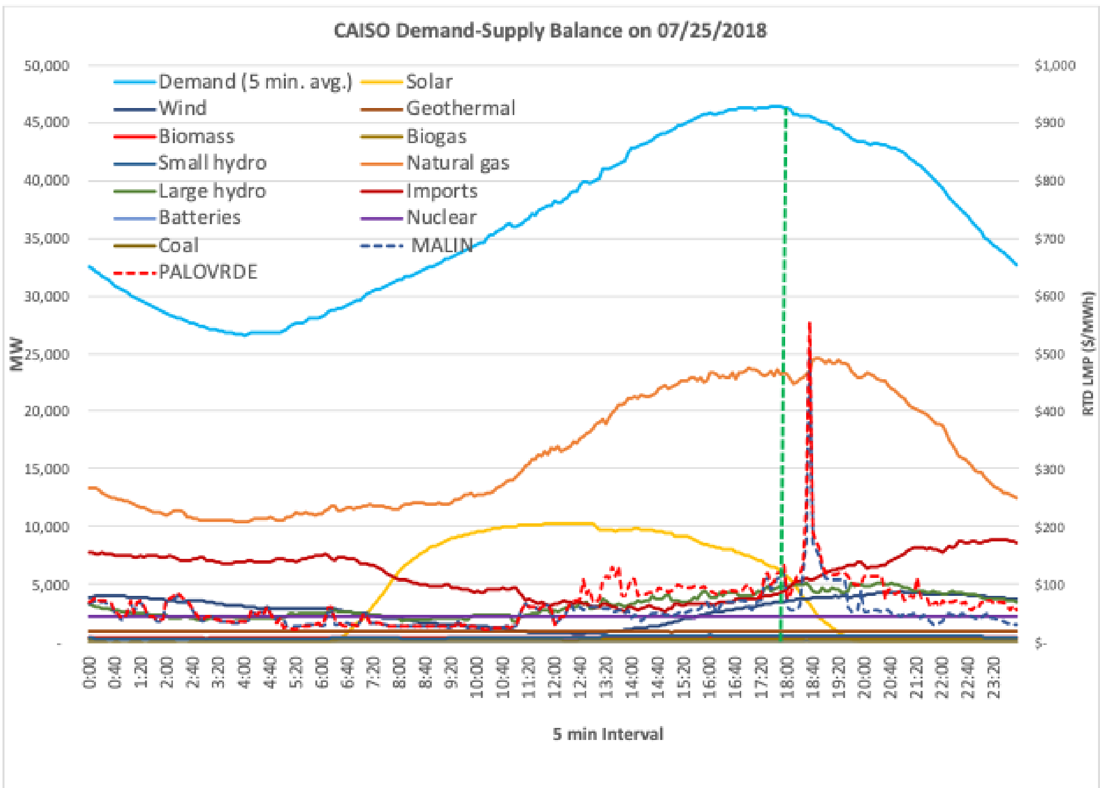
---

19 *Comments of Powerex Corp. on Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portolio* [sic] *and Related Policy Actions*, Dec. 11, 2019, at 1.

20 *Id.* at 2.

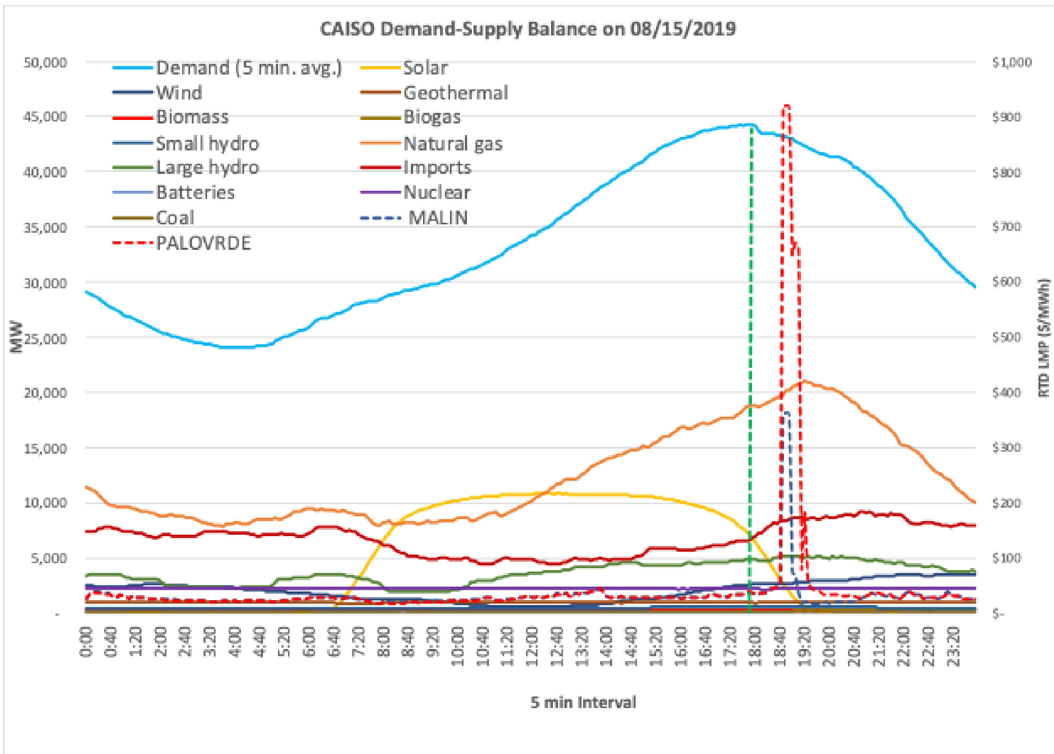
p.m., imports were above 6,000 MW; by 9 p.m., they were 7,600 MW; and at 11:25 p.m., they peaked at 8,941 MW. Powerex attributes reductions in imports to elevated prices in the West, the figure below contradicts their theory. The Palo Verde and Malin price spikes in the middle of the day and after the peak hour, did not materially change the levels of imports before and after the spikes.

Figure 4: CAISO Demand - Supply Balance, July 26, 2019



A similar pattern was observed during the 2019 peak day of August 15, 2019, but in this case, imports happened to be at 6,784 MW during the peak hour (much greater than the peak day in 2018), rising to 8,621 MW at 7 p.m., and a high of 9,189 MW at 9 p.m. The "trend" of reduced peak imports suggested by Powerex, would appear to have reversed itself in 2019. While there was a similar price spike during the evening ramp in 2019, it also did not materially affect the level of imports. Instead, as during the 2018 peak day (and most days), imports were lower during the high solar production hours and higher during the low solar production hours, as discussed in part a. This does not mean the imports could not have served more load if needed during different hours, it just means the efficient CAISO dispatch took the imports when it made sense to do so. See the attached spreadsheets for the underlying data.

Figure 6: CAISO Demand-Supply Balance, August 15, 2019



CalCCA appreciates Powerex's efforts to progress the import discussion and looks forward to further discussions with Staff and stakeholders to get a more workable view of import availability over the planning horizons.

5. Comment on the manual addition of 2,000 MW of "generic effective capacity" in order to produce a portfolio with an LOLE result of less than 0.1. Would you recommend a different way of depicting the reliability gap in the portfolio? If so, describe in detail.

To ensure SERVM simulations that would demonstrate a 0.1 loss of load expectation or better level of reliability for the 46 MMT Alternate Scenario, Staff estimated that 2,000 MW of generic effective capacity would need to be added to the portfolio. The 2,000 MW were added to the study years of 2026 and 2030, meaning it would be online by 2026. No extra capacity was added in 2022, since the 46 MMT Alternate Scenario included a partial extension of existing OTC units that should provide sufficient effective capacity in 2022.

Resolving the discrepancies across SERVM and RESOLVE takes time, presenting challenges in this IRP cycle. It is reasonable that SERVM, a more granular model with more constraints than RESOLVE, would identify a point of failure not identified in RESOLVE—in fact, this is the design and intent of the two model setup, and a certain degree of misalignment between the models should be expected. However, CalCCA encourages staff and stakeholders to better understand why the models fail to align in 2026 and explore resource solutions which best fit the identified gap.

Specifically, Staff's selection of generic capacity in the form of a zero-emission peaking facility does not give sufficient insight into the kinds of resource solutions that will occur in 2026 following the retirement of Diablo Canyon. As noted by Staff, this gap could realistically be met by several resource types—firm imports, battery storage, renewable resources, demand-side management, or thermal generation. It is important that the Commission identify specific resources so that the CAISO's Transmission Planning Process can ensure that the needed transmission can be added to ensure that the resources and energy can be used. The CAISO emphasized this in its *ex parte* notice filed November 27, 2019.[21]

SERVM runs with specified resources in-lieu of the generic capacity will serve two critical purposes. First, these runs will help identify which least-cost, preferred resources or resource characteristics could best meet the 2,000 MW shortfall. Second, they will help

---

[21] *See* CAISO Ex Parte.

determine whether 2,000 MW is in fact the correct capacity to meet the 0.1 LOLE constraint. The potential impact on ratepayers of getting it wrong is significant: 2,000 MW of generic capacity need met by battery storage ultimately lacking the requisite characteristics would impose an unnecessary cost on ratepayers of roughly $8/kW-month (nearly $200 million annually).

C. Electric Sector GHG Target

1. Do you support the 46 MMT Alternate Scenario as the basis for the GHG emissions goal for 2030 to be affirmed by the Commission? Why or why not? If you propose a different scenario, explain your rationale.

The primary assumption changes in the 46 MMT Alternate Scenario, relative to the 38 MMT and 30 MMT scenarios, are related to OTC unit retirements, the deployment of storage, the pace of solar buildout, and potentially greater reliance on new OOS renewable resources. While CalCCA does not oppose the 46 MMT Alternate Scenario's assumptions regarding limited near-term solar resource development and partial OTC (2,289 MW) extension, many CCAs have local requirements that exceed the state's goals and are planning for 30 MMT scenarios or even greater reductions. As discussed above, however, the 5,000 MW import constraint, which likely drives the need for 2,000 MW of generic capacity, appears arbitrary and overly conservative, devaluing the significant investments on the part of California ratepayers in transmission to supply sources across WECC. To the extent the Commission adopts the RSP with generic capacity, it should understand that planning years containing generic capacity (2026 and beyond) require further analysis and vetting before they can be considered meaningful, let alone binding, direction for LSE procurement.

D. Electric Resource Portfolio

1. Are you concerned about the risk of overreliance on solar as part of the recommended portfolio? Why or why not?

The RSP does not present a risk of overreliance on solar resources in the near- or mid-term. The utility-scale solar capacity required to meet policy goals also represents almost a doubling of solar capacity compared to current in-state solar in California. Similarly, the battery capacity selected for this portfolio is approximately 10 GW, which is roughly ten times the installed capacity of batteries nationally in 2018. As CalCCA pointed out in Section I, however, assessment of portfolio needs turns on the planning horizon underlying the question. All signs, today, point to increasing reliance on solar resources as a good strategy.

As the grid and technologies evolve, however, so will California's view of solar, and course correction will be necessary. It is important to keep in mind that California's initial two decades of RPS implementation faced the same degree of anxiety and skepticism, yet the goals have been achieved. The achievement has not been a product of luck, but of planning, innovation, and continued refinement throughout the process. The next decade of California's renewable transition can be achieved through a similar process, as suggested by the wide range of regulatory[22] and industry[23] planning indicating that high solar and storage penetration are feasible, reliable, and cost-effective, particularly when paired with complementary resources such as OOS and offshore wind.

---

[22] CEC / E3 Deep Decarbonization in a High Renewables Future, located at https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

[23] Southern California Edison, Pathway 2045; November 2019, located at https://newsroom.edison.com/internal_redirect/cms.ipressroom.com.s3.amazonaws.com/166/files/201910/201911-pathway-to-2045-white-paper.pdf.

2. Are you concerned about the risk of overreliance on battery storage as part of the recommended portfolio? Why or why not?

The RSP does not present a risk of overreliance on battery storage in the near- or mid-term. The portfolio is not, however, without uncertainty:

- With only 833 MW of battery storage expected to be online by 2020, battery storage is untested at high levels of penetration in California as in other regions;
- The battery capacity selected for this portfolio is approximately 10 GW, which is roughly ten times the installed capacity of batteries nationally in 2018;
- As noted earlier, the RSP may be overly reliant on 4-hour batteries, and additional sensitivities are required to test battery storage of longer duration. Despite these uncertainties, battery storage continues to be a good strategy;
- Given the nature of the storage, location is critical, and there is a need to increase the granularity in identifying the location of storage to ensure its effectiveness; and,
- The pace of technological change all but ensures that new technologies will play an increasing role.

This uncertainty highlights the need for the Commission to avoid procurement directives that order premature storage deployment, because such an approach may prevent deliberate procurement strategies, prevent California from taking full advantages of technological advances, and saddle customers with unnecessary stranded costs.

Developer and LSE incentives are driving configurations and contracting structures that support utilization of battery storage as envisioned in SERVM and other planning exercises. CalCCA encourages the Commission and stakeholders to observe and test battery viability in this and subsequent IRP cycles, with opportunities in the 2021-2022 IRP to refine and correct storage assumptions in line with the tested experience. While battery reliability and degradation are potential areas of performance risk, innovation in controls, chemistry, and other areas are likely to mitigate performance risk on these fronts in coming years.

The 2019 IRP renewable resource portfolios currently under development for the 2020-2021 TPP need to identify the locations of the storage capacity with some degree of granularity. The 2017 IRP portfolio entailed approximately 2,000 MW of Li-Ion battery as the Commission CPUC did not identify their general locations. The 2019 IRP portfolios are expected to have more than 11,000MW of Li-Ion battery storage capacity by 2030.[24] Therefore, the Commission, in coordination with the CEC and the CAISO, needs to play a key role in identifying appropriate locations and types of storage resources. CalCCA believes that the Flexible Capacity Deliverability studies and LCR Economic Assessments performed by the CAISO in the current TPP and 2018-2019 TPP are very useful in identifying the location and attributes of storage resources. In particular, the Flexible Capacity Deliverability Assessment performed by the CAISO in the 2019-2020 TPP[25] could provide a good guideline for the CPUC in locating the selected 2019 IRP storage resources in different *generation pockets*.

Similarly, the CAISO's LCR Economic Assessments should inform the amount of battery storage that could be located in the various *load pockets*. These studies are also very informative in identifying the attributes of the required storage resources. Additionally, the Commission should provide guidance on defining an adequate amount of utility-side (front-of-the-meter) solar resources that could be co-located in local areas or sub-areas to ensure that there is adequate generation available to charge the battery storage.

The Commission should review and revise regulatory structures that may limit LSE investment in hybrid and standalone storage, such as uncertainty in accounting and future ELCC revisions for storage. In particular, CalCCA encourages the Commission to adopt a vintaging

---

24 CPUC Energy Division, *2019-20 IRP: Proposed Reference System Portfolio Validation with SERVM Reliability and Production Cost Modeling*, Nov. 6, 2019, at 17.

25 *Flexible Capacity Deliverability Assessment*, 2019-2020 Transmission Planning Process Stakeholder Meeting, Nov. 18, 2019, at 20-29.

methodology for battery storage and other resources that face ELCC derating due to saturation, which today represents a significant barrier for LSEs to pursue long-term storage investments that rely on resource adequacy value as a significant revenue stream.

Finally, the Commission should focus on improving the strategic location of storage resources to address local capacity requirements by increasing the accuracy of and utilizing the busbar mapping. The efforts to improve effectiveness through location should, moving forward, align with resilience efforts to mitigate reliability impacts from Public Safety Power Shutoffs and other public safety emergencies.

3. Is the retention of most or all of the current thermal generation fleet reasonable and realistic? Why or why not?

As indicated in response to Question 6, approaching the question of retention of thermal generation as a binary choice oversimplifies the issue. Criteria pollutant emissions levels, which depend upon technology and capacity factors, and resource location add granularity to the analysis that will better enable the Commission to determine whether thermal generation retention is "reasonable and realistic." In addition, CalCCA supports conducting the thermal retention special study to specifically examine the costs associated with greater or slower thermal retirements. Throughout, these costs must be evaluated compared to the accelerating costs climate change is imposing on California through drought, wildfires, changing hydrological regimes, and sea level rise.

Without consideration of these factors, RESOLVE chooses not to economically retain approximately 3.7 GW of the existing thermal generation in 2030, leaving 21 GW in operation. Retention of some amount of thermal generation may be appropriate until alternative technologies can be deployed to reduce the reliance on thermal generation without impairing reliability. Such solutions may include a hybrid electric gas turbine that combines the storage resources with gas plants, which would potentially allow for a smaller fleet of gas resources while a fully decarbonized grid is deployed.

4. Do you have additional comments about the portfolio associated with the 46 MMT Alternate Scenario?

CalCCA has no comment at this time, but notes that many CCAs are under local carbon reduction requirements that are more rigorous.

E. Commission or LSE Actions in Response to Portfolio Recommendation

1. Should the Commission take steps to begin development of transmission and/or generation from geothermal resource areas? If so, what steps? If not, why not?

As a preliminary matter, CalCCA questions whether these comments are the appropriate place to ask this question. Whether or not the expense of additional transmission and generation in geothermal areas is warranted depends in large part upon the portfolios presented by LSEs and the suitability of the portfolios to achieving decarbonization and reliability goals. These comments should appropriately focus on modeling and portfolio development.

With this reservation, some resources, including baseload renewables (geothermal and biomass) and alternative storage (pumped hydro) present distinct and, at times, complementary attributes to the growing fleet of solar, wind, and battery storage resources. However, there is little evidence within the proceeding record which supports the significant above-market investments in both generation capacity and transmission capacity required to develop these resources at a significant scale. Although no geothermal specific special study was scoped in the RSP analysis in the February 11, 2019, ruling, this question may be appropriate for further analysis. That said, refined modeling within the 2019-2020 modeling cycle, with improved cost assumptions, does not expect new build geothermal to be a part of the resource mix through 2030 outside of specific sensitivity cases.

A number of stakeholders have expressed concerns regarding the inequity faced by developers of certain renewable resources which have been overlooked by LSEs and planning exercises seeking least-cost, best-fit resources. In particular, these renewable resources represent one approach to addressing periods of persistent low generation from solar and wind, although other approaches, such as regional integration may also address such concerns. Despite the unique benefits offered by these resources, these benefits may not outweigh the significant costs associated with these resources relative to other, more cost-effective technologies which provide similar benefits. Ultimately, the Commission should consider additional studies of such conditions and the loss of load expectations associate with these functionalities.

The Commission should be cautious not to burden ratepayers with unnecessary above-market costs in order to address inequities between groups of corporate developers of renewable projects with unfavorable economics. California should keep its sights set on decarbonization and reliability, rather than choosing technology winners and losers absent compelling cost-benefit analyses.

2. Should the Commission take steps to support the development of at least one pumped storage facility in California? If so, what steps? If not, why not?

Again, CalCCA observes that this question may be more appropriately addressed after LSEs have provided their individual IRPs; the purpose of the inquiry in these comments should be limited to the development of the RSP. RESOLVE includes only 85 MW of pumped storage. The resource comes online in 2026, and it is built under only the most stringent—30 MMT—GHG target. In light of these circumstances, no pumped storage should be considered in the medium term at this time.

Whether or not pumped storage is included in the RESOLVE model, however, does not prejudge procurement of these resources. While the Commission suggests that the capital-intensive nature of pumped hydro could act as a barrier to individual LSEs investing in the resource, CCAs already can and do coordinate to procure larger projects. For example, a collaborative effort between Monterey Bay Community Power and Silicon Valley Clean Energy procured what was California's largest solar and storage facility at the time.[26] CalCCA members are currently exploring building on this multi-CCA model to pursue even larger needed projects to address our collective local requirements. Among these, CalCCA members are investigating pumped storage projects and will pursue this option if cost-effective development opportunities arise.

3. Are there other actions the Commission should take specifically with respect to replacement capacity for the Diablo Canyon nuclear plant? Describe in detail.

CalCCA encourages the Commission to pursue further modeling and analysis related to the Diablo Canyon Power Plant closure. While the IRP models incorporate high-level planning around the DCPP closure, the significant supply shock associated with DCPP's retirement may warrant further, more granular analysis to ensure resource sufficiency in 2025 and beyond. Specifically, the generic resource build results from the RESOLVE process should be incorporated into a more sophisticated, more granular model that can confirm system reliability. As noted elsewhere, the 2,000 MW generic capacity stop-gap incorporated into SERVM to address the 2026 model year gap indicates that further analysis is needed. This further modeling, together with collective action developed through the IRP process, will ensure a successful retirement of California's last nuclear power plant.

---

[26] Located at https://www.prnewswire.com/news-releases/largest-california-solar-plus-storage-project-agreement-signed-between-canadian-solar-subsidiary-recurrent-energy-silicon-valley-clean-energy-and-monterey-bay-community-power-300740151.html

Decommissioning of DCPP will require resource replacement to shore up system reliability. As the Commission recently directed in D.19-11-016, any *system* RA deficiency created by DCPP retirement should allocated to all LSEs within the three IOU TAC areas based on their load ratio share. To enable this determination, SERVM should isolate DCPP impacts on reliability needs using a "DCPP in/out" methodology.

4. Are there other actions the Commission should take with respect to development of any other types of capacity or resources such as offshore or out-of-state wind? Describe in detail.

At least two CCAs have begun to explore offshore wind opportunities, and CalCCA suggests examining the integration of these resources in the 2026 and 2030 scenarios. Offshore wind represents a new and promising resource for California which complements the generation profiles of both on-shore wind and solar and thus could prove to be a critical renewable integration strategy.

CalCCA appreciates the Staff's new modeling that allowed RESOLVE to build new transmission for 3 GW of OOS wind resources as a default assumption. Although the 46 MMT case did not select any OOS wind resource dependent on new transmission, the more stringent GHG targets, such as 38 MMT and 30 MMT, select highly significant amounts of OOS wind.[27] It is also important to note that the OOS wind resources are cost-effective under 30 MMT target, even under higher transmission cost assumptions. Overall, the Staff's updated analysis suggests that the OOS wind resources need to part of the future portfolios, even taking into account cost of new transmission infrastructure.

Indeed, California CCAs may find development of resources outside of California to be an effective strategy for addressing affordability concerns around decarbonization if those

---

[27] Ruling Seeking Comment, Attachment A (2019-20 IRP: Proposed Reference System Plan), slides #98-99.

resources prove to be more cost effective. Critically, the transmission and out-of-state wind sensitivity analyses suggest that increased reliance on new transmission to cost-effective out-of-state wind could save Californians hundreds of millions or billions of dollars annually, depending on the costs of transmission, although at least 5 GW of out-of-state wind is selected in all cases at the 30MMT scenario.[28] For those LSEs that are moving faster toward the state's goals, these cost considerations will be significant in designing portfolio plans. While CalCCA is mindful of objectives around local economic activity, at a time when high and climbing electricity rates are already a matter of grave concern for many communities, the Commission should support efforts to rely on such new resources for both energy and RA capacity.

F. CAISO TPP Recommendations

1. Comment on the recommendation to use the 46 MMT Alternate Scenario as the reliability and policy-driven base cases for the next CAISO TPP.

The CAISO uses the reliability and policy-driven IRP base cases to identify transmission upgrades needed that, once identified, will proceed directly to the planning stage and be brought to the CAISO board for consideration. The base case recommended for this purpose is the 46 MMT Alternate Scenario.

CalCCA supports the 46 MMT Alternate Scenario for reliability and policy-driven bases cases. This support, however, is contingent on a robust feedback loop between the IRP and CAISO TPP that includes stakeholder feedback on the busbar mapping process. In addition, as noted in response to Question 5, however, the CAISO requires greater specificity in the 2,000 MW generic effective capacity addition, and the RSP should be further refined to address this shortfall prior to its adoption and transmission to CAISO for purposes of transmission planning.

[28] CPUC Energy Division Presentation "2019-2020 Preliminary IRP results," Oct. 4, 2019, at 87 and following.

In the CAISO's *Ex Parte* discussed earlier the CAISO suggested three possible methods for correcting this problem.[29] CalCCA encourages the Energy Division to work with the CAISO to find an acceptable method to ensure that the TPP accurate models the expected portfolio.

2. Comment on the recommendations for policy-driven sensitivities around curtailment in particular transmission zones and the associated impact on EO or full deliverability for renewables.

The CAISO provides the transmission capability limits and upgrades cost estimates used as a direct input into RESOLVE for the IRP analyses to ED staff annually. Currently, if a transmission zone does not have dispatchable resources, the CAISO assumes a 20 percent exceedance level of curtailment of new resources would be possible during summer peak load conditions, based on the current on-peak deliverability methodology, but does not provide an energy-only capability number. A zero EO limit is assumed for those areas in RESOLVE. The Staff has proposed to collaborate with the CAISO staff during the 2020-2021 TPP cycle to incorporate less stringent EO limits than estimated in the past. The Staff has proposed two different approaches comprising new EO limits incorporated into RESOLVE allow the model to build new generation in more transmission zones.

These updated EO limits would be developed under the assumption that an increased amount of curtailment would be permitted in various transmission zones. In particular, the current proposal is to have a *Policy-Driven Sensitivity 1*, which includes LEVEL 1 updated EO transmission capability estimates by expanding the EO transmission capability estimates for zones, which had capabilities previously marked as TBD or which required minor upgrades to accommodate EO resources. The *Policy-Driven Sensitivity 2*, in addition to LEVEL 1 estimates, LEVEL 2 will increase the EO transmission capability estimates for zones with relatively low-

[29] CAISO Ex Parte.

cost upgrades by the same amount as the incremental capability provided by the corresponding upgrade. CalCCA is not opposed to selecting one out of the two suggested policy-driven sensitivities with a preference towards the *Policy-Driven Sensitivity 1* as the EO estimates therein do not rely on any new additional transmission upgrades.

Instead of the proposed *Policy-Driven Sensitivity 2*, CalCCA recommends that the Staff utilize a portfolio that is based upon the transmission capability estimates reflecting CAISO's revised deliverability methodology.[30] The implementation of the revised methodology would result in accommodating more full capacity deliverability status resources in a given transmission area than under the existing methodology without triggering the need for additional transmission upgrades. The CAISO has found that several upgrades identified using the current methodology would not be needed under the new methodology. Since the CAISO, in its 2020-2021 TPP, is expected to deploy its revised deliverability assessment for the policy-driven assessment, it is appropriate to provide at least one sensitivity portfolio, if not the base portfolio itself, that is based on the consistent set of assumptions.

3. Comment on the suggested process for seeking formal input on busbar mapping of the proposed RSP.

The mapping process being conducted by the CEC and Commission staff—a valuable contribution to identifying key locations for resource deployment—is not yet complete. To provide a more efficient process, while also allowing formal input from parties on the mapping process, this ruling proposes to have the busbar mapping process proceed on a parallel path with the adoption of the RSP. To facilitate this, a separate ruling will be issued in the near future with details of the busbar mapping and seek party comments on the methodology and the results.

[30] For more details on this proposal, see the CalCCA's July 19, 2019 comments on the June 17, 2019 workshop and the Unified RA and IRP Modeling Databases released June 28, 2019 and revised July 15, 2019, at 5-6.

The 2019 IRP renewable resource portfolios currently under development for the 2020-2021 TPP need to identify the locations of renewable capacity, in general, and storage, in particular, with some degree of granularity. The 2017 IRP portfolio utilized in the 2019-2020 TPP entailed approximately 2,000 MW of Li-Ion battery. However, the CAISO did not model them in the 2019-2020 TPP studies at all as the ED did not identify their locations. The 2019 IRP portfolios are expected to have more than 10,000 MW of Li-Ion battery storage capacity by 2030.[31] Therefore, the Commission, in coordination with the CEC and the CAISO, needs to play a key role in identifying appropriate locations and types of storage resources. CalCCA believes that the *Flexible Capacity Deliverability* studies and the LCR Economic Assessments performed by the CAISO in the current TPP and 2018-2019 TPP are very useful in identifying the location and attributes of storage resources. In particular, the *Flexible Capacity Deliverability Assessment*[32] performed by the CAISO in the 2019-2020 TPP could provide a good guideline for the CPUC in locating the selected 2019 IRP storage resources in different generation pockets.

Similarly, the CAISO's *Local Capacity Requirements (LCR) Economic Assessments* should inform the amount of battery storage that could be located in the various load pockets. The *LCR Economic Assessment* studies are also very informative in identifying the attributes of the required storage resources. These studies are also very informative in identifying the attributes of the required storage resources. Additionally, the Staff should provide guidance on defining an adequate amount of utility-side solar resources that could be co-located in local areas or sub-areas to ensure that there is adequate generation available to charge the battery storage.

---

[31] CPUC Energy Division, *2019-20 IRP: Proposed Reference System Portfolio Validation with SERVM Reliability and Production Cost Modeling*, Nov. 6, 2019, at 17.

[32] *Flexible Capacity Deliverability Assessment*, 2019-2020 Transmission Planning Process Stakeholder Meeting, Nov. 18, 2019, at 20-29.

CalCCA is concerned that there is no opportunity for stakeholders to review the proposed busbar mapping and to provide informed input before the final portfolios along with resource mapping are conveyed to the CAISO. It is pertinent that stakeholders are kept in the loop in case the CAISO discovers issues with the proposed busbar mapping as they begin analyzing the resource portfolios in the 2020-2021 TPP cycle.

G. Proposed Aggregation Process for the 2020 PSP

1. For a particular resource type and zone, where the aggregated resources in LSE plans exceed the resource potential, this suggests that some portion of the selected resources are non-viable from an economic, environmental, or land use perspective. What level of exceedance over resource potential is acceptable, if any, before staff should reallocate resources when aggregating resource choices to form a PSP?

Staff suggest a refined approach to aggregating individual IRP resource choices in 2020. The refined approach entails clarifying for LSEs how information in their portfolios and broader plan filings will be used to inform the development of the 2020 PSP, reducing Commission staff's manual reallocation of MW values in LSE plans to better fit at the system level, reducing potential for errors; and identifying for stakeholders what will happen in the event that LSE portfolios, in aggregate, differ from the RSP adopted by the Commission.

Subsets of CCAs will coordinate procurement in particularly valuable, which should reduce the cases of aggregated resources in LSE plans exceeding the resource potential in certain areas. CalCCA recommends a 20 percent threshold exceedance level over resource potential given that resource specificity, particularly in the out years, will be subject to refinement based on market conditions and availability. Some level of flexibility is required and any such exceedance needs to be further studied in the preliminary CAISO TPP analysis to determine whether such exceedance trigger the need for any major transmission upgrade.

To understand how the 20 percent exceedance could be implemented, let us use the theoretical scenario included in the ALJ Ruling where the initial aggregation of LSE portfolios identifies 600 MW of FCDS wind in the *Carrizo* zone in 2022, which is 413 (=600-187) MW in excess of the FCDS capability of the existing transmission system. Rather than reallocating the entire 413 MW to the nearby zones, such as *Kern_Greater_Carrizo* and *Tehachapi*, only a portion of it, *i.e.*, 375.6 MW of will be reallocated and the remaining 224.5 MW will be modeled in Carrizo. The CAISO's preliminary TPP analysis will verify whether the additional 20 percent capacity, *i.e.*, 37.4 MW (=187 times 20 percent) could be accommodated without triggering the need for any transmission upgrades. CalCCA also notes that since the CAISO is expected to deploy its revised deliverability methodology in the 2020-2021 TPP, almost all zones would likely be able to accommodate more FCDS resources than envisioned based on the earlier methodology.

2. What showings should LSEs be required to make to demonstrate that deviations, if any, between the aggregation of LSE portfolios and the RSP are appropriate and necessary to better adhere to the IRP statutory requirements?

While the RSP provides a useful benchmark and starting point for the state's planning exercise, it does not and cannot reflect the individual needs and desires of each LSE, and the IRP process must not ignore insights and outcomes of individual LSE planning efforts. The IRPs under development by CalCCA's members are intended to meet both statewide policy goals, as well as local policy mandates and preferences. Many of these plans will aim to meet more aggressive GHG targets, incorporate local development preferences, require meeting load with renewables for each hour of the year, and incorporate greater demand-side management and beneficial electrification.

The likelihood that these plans will deviate from the RSP has increased recently as CCAs have turned their focus to resilient local solutions to mitigate the impacts of Public Safety Power Shutoffs, including traditional, customer-sited behind-the-meter solutions, as well as local microgrids with resources in front of the meter.[33] For these reasons, the strategies to achieve the state's goals are likely to differ from the strategies and mix selected by the RSP, and may result in an aggregated portfolio with greater costs borne by the LSEs that pursue those costs.

CalCCA supports requiring LSEs to provide supporting documentation and justification for these deviations, including qualitative and quantitative support. Qualitative evidence could include reference to local policy or legal requirements requiring deviation. Quantitative support could include analysis demonstrating portfolio compliance with overarching policy goals such as decarbonization and reliability, such as PCM assumptions and outputs. CCAs intend to make relevant quantitative data available to illuminate any plan deviations, subject to the restrictions of D.06-06-066 and the Public Records Act, and expect other market participants will do the same. The Commission should require LSEs to identify any deviations in an Appendix and provide all supporting qualitative and quantitative support as a part of the Appendix.

3. What criteria should Commission staff use to determine whether transmission upgrade needs identified by LSEs in their IRPs are appropriate to be reflected in the PSP and the TPP reliability base case adopted by the Commission?

Under the proposed Staff aggregation approach, LSEs may trigger an upgrade not identified in the RSP if the LSEs communicate that they are actively planning for the upgrades, and can justify the cost, timeline, and risks.

[33] *See, e.g.,* Redwood Coast Airport Renewable Energy Microgrid, located at https://redwoodenergy.org/community-choice-energy/about-community-choice/power-sources/airport-solar-microgrid/.

CalCCA recommends an alternative approach to addressing zone constraints, since addressing constraints through upgrades may be a superior solution to resource relocation. Since upgrades would be triggered mostly through collective impacts, it is unlikely that any individual LSE would have the needed visibility into other LSE plans to know there would be a need for an upgrade, so it is unlikely any individual LSE would be planning for upgrades resulting from collective impacts. That does not mean that CAISO would not find the upgrade to be cost effective when it examines the collective impacts, however. Thus, CalCCA recommends that where a zonal constraint is triggered, the Commission consult with CAISO on how such a constraint could be alleviated, rather than resorting immediately to relocation assuming such a constraint would not be cost effective to address.

4. Provide any other comments on the Commission staff-proposed aggregation approach, including any process suggestions for how LSEs can more effectively participate or give input to the planning process.

CalCCA generally does not object to Staff's proposed aggregation process as outlined in the Ruling.[34] In Staff's process of reallocating resources in oversubscribed zones, however, the Commission should provide affected LSE's, collectively, notice in a public posting and an opportunity to propose an alternative before performing the reallocation as specified in the Ruling.

---

[34] Ruling Seeking Comment at 33-36.

III. CONCLUSION

For all of the foregoing reasons, CalCCA respectfully requests consideration of the proposals specified herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

December 17, 2019

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
Counsel to the California Community Choice Association

EXHIBIT A

CalCCA Seven-Hour FOM Battery Storage Scenario

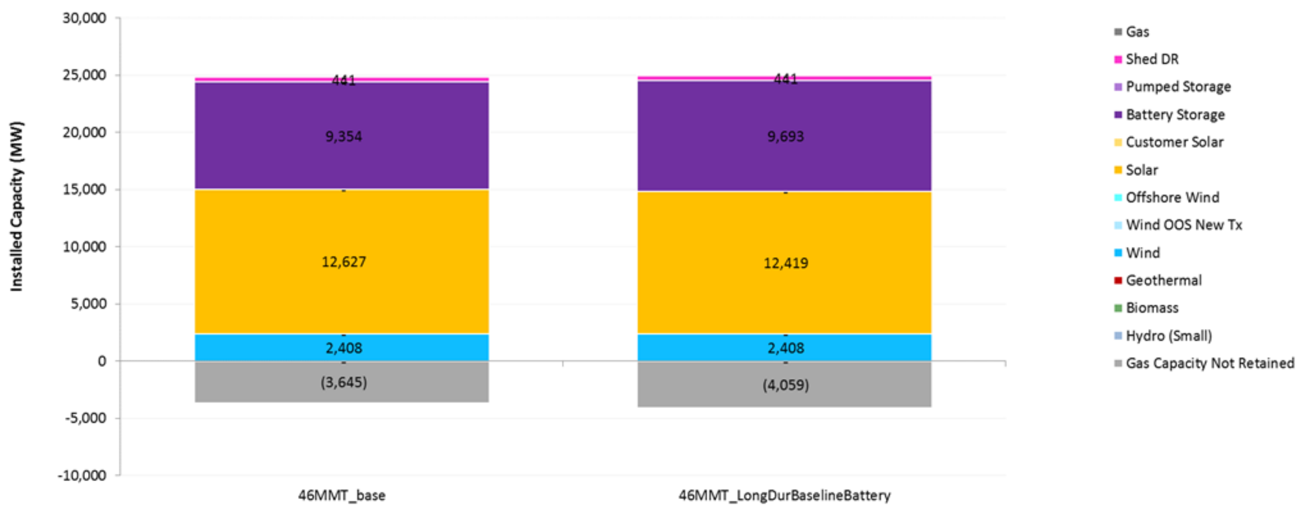
RESOLVE currently does not have the functionality to identify the optimal duration of storage to meet varying amounts identified in CAISO's LCR studies. To better understand how RESOLVE results might be affected by changing battery storage duration, CalCCA ran a sensitivity scenario using the Oct 4th 46 MMT Base Case, where we forced the baseline utility-scale FOM storage of about 1,479 MW by 2030 to all be 7-hour Li-Ion battery storage instead of the default 4-hour battery as a proxy for longer duration storage capacity. The results of this longer duration battery storage case shows that such higher duration storage reduces the need for the duration of the other storage resources, especially in the years 2022 and 2026.

RESOLVE does not allow for the flexibility to select different levels of battery storage capacity with different durations. Therefore, in order to have at least some Li-Ion battery storage with a longer duration, CalCCA used the feature of RESOLVE allowing users to fix the duration of the "baseline" battery storage only, forcing the assumed 4-hour baseline battery storage assumed in the 46 MT Base case (*i.e.,* 1,479 MW by 2030) to 7-hour duration. With the modified baseline, RESOLVE then "selects" the amount of battery discharge energy that is needed to meet the various constraints. The resultant average duration of that optimized built Li-Ion battery storage capacity (*i.e.*, the ratio of energy and capacity) is reduced in the case when the baseline battery storage had a longer duration (7-hour) versus in the cases when it has a shorter duration (4-hour). See the highlighted values in yellow in the table below that compares the Li-Ion storage duration by 2030 in the two cases.

	4-Hour Duration - 46 MMT				7-Hour Duration - 46 MMT			
Planned & Optimized Build	2020	2022	2026	2030	2020	2022	2026	2030
Planned Baseline Li_Ion Battery Duration	4.0	4.0	4.0	4.0	7.0	7.0	7.0	7.0
Optimized Build Li_Ion Battery Duration	-	4.0	3.5	3.7	-	1.9	2.5	3.4

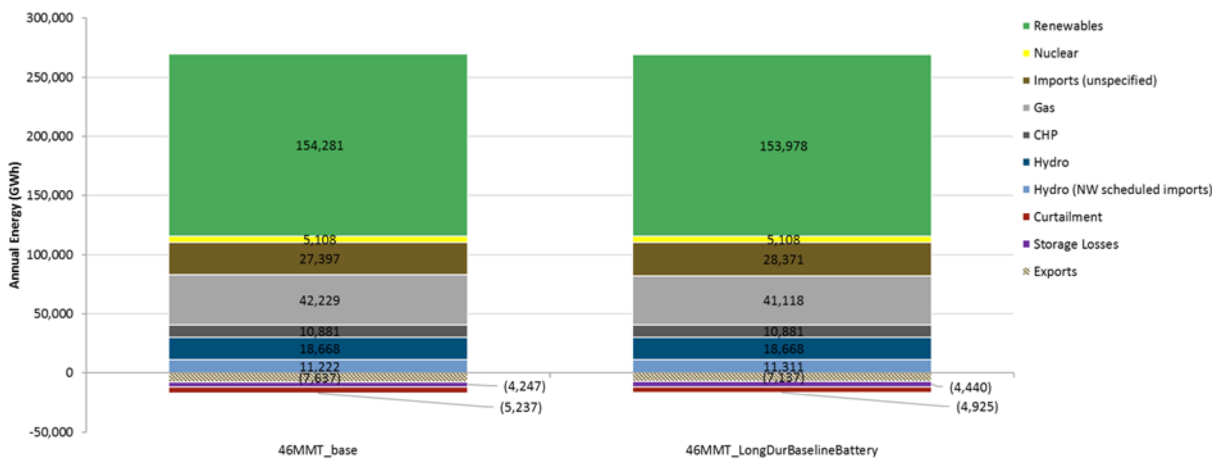
Using longer duration storage also reduces total curtailments relative to the Base 46 MMT case and most importantly, reduces the need to retain the gas-fired generation in 2030 as shown in Figure 1 below. It reduces the dispatch of CCGT units, reducing the need to retain gas-fired generation. In particular, by 2030, more than 400 MW of additional gas capacity is not retained in the longer duration battery storage case relative to the 46 MMT base case.

Figure 1: A Comparison of Installed Capacity (MW) in the 46 MMT case with 4-hour vs. 7-hour Duration Baseline Li-Ion Battery Storage Capacity in 2030



As shown in Figure 2 below, the reduced reliance on the gas-fired generation (from 42,229 GWh to 41,118 GWh) is made up of a combination of increased duration of the battery storage dispatch, increased reliance on unspecified imports (increased from 27,397 GWh to 28,371), reduced exports (from 7,637 GWh to 7,137 GWh) and curtailments (from 5,237 GWh to 4,925 GWh). These findings show that the higher duration battery storage also reduces renewable curtailments as well as exports. In the November 6th cases when the imports are restricted for all hours to 5 GW, we did not find that the longer duration storage had any significant impact on the gas-fired generation retention, CCGT dispatch, unspecified impart, exports or curtailments.

Figure 2: A Comparison of Generation (GWh) in the 46 MMT case with 4-hour vs. 7-hour Duration Baseline Li-Ion Battery Storage Capacity in 2030



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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2018)

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION GRANTING MOTION REGARDING QUALIFYING CAPACITY VALUE OF HYBRID RESOURCES WITH MODIFICATIONS

Irene K. Moosen
Director, Regulatory Affairs
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
Regulatory@cal-cca.org

Evelyn Kahl
Ann Springgate
Buchalter, A Professional Corporation
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
ekahl@buchalter.com

Counsel to the
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

December 20, 2019

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2018)

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION GRANTING MOTION REGARDING QUALIFYING CAPACITY VALUE OF HYBRID RESOURCES WITH MODIFICATIONS

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the California Community Choice Association (CalCCA)[1] submits the following comments on the *Proposed Decision Granting Motion Regarding Qualifying Capacity of Hybrid Resources with Modifications,* issued on November 26, 2019 (Proposed Decision or PD).

I. INTRODUCTION

The Proposed Decision adopts an interim methodology for determining the Qualifying Capacity (QC) for "hybrid resources" with charging or other operating restrictions. CalCCA appreciates the PD's recognition of the urgent need to address hybrid resource QC calculations. The PD's approach, however, is uninformed by a fulsome exploration of alternatives, lacks the clarity necessary for successful implementation and risks shortchanging the value of hybrid resources.

---

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

Devaluing hybrid resources, particularly at a time when these resources are increasingly viewed as the key strategy for system reliability, would be counterproductive. The proposed methodology would effectively eliminate the resource adequacy (RA) value of either the Variable Energy Resource component or the storage component of hybrid resources for portions of the year. This would present a significant barrier for LSEs seeking to urgently develop these resources in line with near-term needs identified by the Commission in Decision (D.) 19-11-021.

The RA value of hybrid resources must be timely resolved. Unfortunately, the PD does not resolve the surrounding uncertainty and, in fact, adds yet another complicating factor. Adopting the PD also risks creating a false sense of security that the issue has been addressed. CalCCA thus requests that the Commission defer adoption of the proposed methodology until stakeholders have fully explored alternatives. The Commission should, instead, turn its full attention to developing a permanent methodology using the process and timeline recommended in Section III.

If, despite the concerns raised in these comments, the Commission moves forward with an interim methodology, CalCCA requests two clarifications to minimize uncertainty and enable LSEs to timely meet the requirements set by D.19-11-021. To increase certainty, the Commission should clarify the PD to provide as follows:

- ✓ The PD's methodology will not apply to co-located resources with two or more California Independent System Operator (CAISO) resource IDs and a common point of interconnection (Co-located Resource), even if the resource has "charging or operational restrictions."
- ✓ "Charging or operational restrictions" means restrictions that require a battery to be charged exclusively from the paired renewable resource to obtain the Investment Tax Credit (ITC) for hybrid resources.

Proposed findings of fact, conclusions of law and ordering paragraphs implementing these changes are provided in Appendix A.

II. THE PD DOES NOT REDUCE UNCERTAINTY

Engie Storage, Enel X, Tesla, Inc., Sunrun Inc., Center for Energy Efficiency and Renewable Technologies, California Energy Storage Alliance, and Vote Solar (Joint Parties) requested a schedule and process for determining the QC of hybrid resources, including both in front of the utility meter (IFM) and behind the utility meter (BTM) resources.[2] They further requested adoption of an interim methodology for determining the RA value of these resources. The Joint Parties highlighted the need for timely action on these requests to allow developers to effectively participate in resource solicitations and allow load-serving entities (LSEs) to understand the value of the resources in their supply plans.[3]

The Proposed Decision does not fully respond to the Motion's requests, addressing an interim methodology but providing no process for a permanent methodology. Ordering Paragraph 2 grounds the decision in a definition of hybrid resource: "a generating resource co-located with a storage project, having a single point of interconnection and represented by a single market resource ID."[4] The PD limits the scope of its interim rule to "hybrid resources with operational restrictions." It adopts San Diego Gas & Electric Company's (SDG&E's) conservative proposal to set the QC value for these resources:

> [T]he larger of (i) the effective load carrying capability (ELCC)-based QC of the intermittent resource or the QC of the dispatchable resources, whichever applies, and (ii) the QC of the co-located storage device.[5]

---

2 *Joint Motion of Engie Storage, Enel X, Tesla, Inc., Sunrun Inc., Center for Energy Efficiency and Renewable Technologies, California Energy Storage Alliance, and Vote Solar to Establish a Schedule and Process for Determining the Capacity Value of Hybrid Resources* (Motion), filed September 27, 2019.

3 Motion at 3.

4 *Id.*

5 *Id.* at 6.

Given the likelihood that the final methodology will differ from the interim methodology, adopting SDG&E's proposal at this time provides little, if any, certainty to LSEs and developers in the procurement of hybrid resources. Further perpetuating uncertainty, the PD does not provide a procedural schedule or target implementation date for developing a permanent counting methodology.

III. THE COMMISSION SHOULD DEFER CONSIDERATION OF THE PD'S PROPOSED METHODOLOGY AND, INSTEAD, ESTABLISH A TIMELINE FOR EXPEDITIOUS DEVELOPMENT OF A PERMANENT METHODOLOGY

As the Joint Parties emphasized at the December 16, 2019, workshop in Rulemaking (R.) 19-11-009, hybrid resource QC counting methodologies— both IFM and BTM—have languished in Commission proceedings. While the PD attempts to address this delay, jumping to a very conservative solution without adequate exploration of alternatives only creates more uncertainty. Instead, the Commission should defer adoption of an interim methodology and provide a clear process and timeline to ensure permanent hybrid resource methodologies are adopted no later than June 2020. Certainty is particularly important in light of the Commission's requirement to develop *new* reliability resources—a requirement that excludes from eligibility nearly all options but paired renewable and battery storage resources.

Given the success of the Working Group process in R.17-06-026, CalCCA encourages the Commission to consider a working group process here, co-led by the Joint Parties, SDG&E, Southern California Edison Company (SCE) and the CAISO. The process should provide for expedited resolution, with a minimum of one public workshop and a workshop report, followed by comments and a proposed decision. CalCCA recommends the following schedule:

Final Decision	1/16/2020
Straw Proposal from Co-Leads	1/31/2020
Workshop	February – date to be set by co-leads
Workshop Report	Workshop + 14 days
Opening Comments	Workshop Report + 10 days
Reply Comments	Opening Comments + 7 days

Given the overlap with R.19-11-009, CalCCA recommends submission of the workshop report both in this docket and in R.19-11-009, to enable coordination of a resolution of this issue with the Commission's planned June 2020 decision.

IV. IF THE COMMISSION MOVES FORWARD WITH AN INTERIM METHODOLOGY, IT MUST CLARIFY ITS SCOPE OF ACTION

A. Clarify that the Interim Methodology Will Not Apply to Co-Located Resources Even If Charging or Operational Restrictions Exist

Ordering Paragraph 2 defines "hybrid resource," for purposes of the interim methodology, as "a generating resource co-located with a storage project, having a single point of interconnection and represented by a single market resource ID."[6] The interim methodology is then applied only to hybrid resources with "charging or other operational restrictions."[7] And, by implication, the PD thus suggests that the methodology does not apply to Co-located Resources, which maintain two or more resource IDs. The Commission should confirm its intent to limit any interim action to "hybrid resources" as defined in Ordering Paragraph 2.

Despite the clarity of the Ordering Paragraphs, the PD introduces ambiguity in its narrative focus on operational restrictions, rather than the number of resource IDs. For example, it states: "Where neither resource component has operational restrictions, we see no reason for the two components to be combined into a hybrid resource for QC purposes."[8] The PD continues: "it is unnecessary to adopt a QC methodology for hybrid resources without

6 Proposed Decision, Ordering Paragraph 2, at 11.
7 *Id.*, Ordering Paragraph 1, at 11.
8 *Id*. at 8.

operational restrictions."[9] In these provisions, the PD appears more concerned about operating restrictions than the number of resource IDs.

CalCCA agrees with a straightforward interpretation of the Ordering Paragraphs: it is unnecessary to impose restrictions on Co-located Resources at this time. As the CAISO has explained, these resources should be treated differently from Co-located Resources "because co-located resources with two or more resource IDs and a common POI are effectively two separate and distinct resources."[10] Notably, Co-located Resources face performance requirements under the CAISO tariff—each component being separately bound by a Must Offer Obligation to fulfill RA requirements.

If the Commission takes interim action, CalCCA requests clarification that the interim methodology does not apply to Co-located Resources. This clarification is critical to give LSEs seeking to deploy these resources confidence to timely execute contracts to respond to the Commission's procurement directive in D.19-11-021.

B. Define "Charging or Operational Restrictions" as a Requirement to Charge a Battery Exclusively by the Paired Renewable Resource

Whether the PD's proposed QC counting methodology applies to a hybrid resource depends on whether the resource "has charging or other operational restrictions."[11] Nowhere, however, does the PD define this phrase. Without a clearer definition, the Commission may inadvertently apply the interim methodology to *all* hybrid resources—which does not appear to be the PD's intent.

---

9 *Id.*

10 CAISO *Hybrid Resources Revised Straw Proposal*, Dec. 10, 2019, at 8-9. www.caiso.com/InitiativeDocuments/RevisedStrawProposal-HybridResources.pdf

11 Proposed Decision, Ordering Paragraph 1 at 11.

The PD refers to these restrictions in its discussion of parties' positions.[12] It observes that SCE identified "facilities receiving the Investment Tax Credit (ITC) that requires the battery to charge primarily from the paired renewable facility."[13] It also references SDG&E's approach for resources with "operational restrictions," but provides no further illumination. A hybrid resource could have a variety of different "restrictions" that would not materially affect the availability of the resource when needed, such as warranty and performance requirements. A restriction could, for example, prohibit charging in peak hours and require charging in off-peak hours or limit the number of charge/discharge cycles.

To avoid the need to fully explore the potential range of operating or charging restrictions, CalCCA proposes adoption of a modified version of SCE's and SDG&E's qualifications. The "restrictions" that trigger application of the hybrid resource interim methodology should include only limitations that require a hybrid resource battery to charge "exclusively" from the paired renewable facility to obtain the ITC. This bright line approach distinguishes hybrid resources that rely exclusively on paired renewable facility availability for charging from those that are capable of being charged from the grid. This definition is straightforward and clear and likely addresses the central issues of concern in this debate.

V. CONCLUSION

For all of the foregoing reasons, CalCCA requests that the Commission defer adoption of an interim methodology. Instead, the Commission should adopt a clear, expedited timeline for developing a permanent hybrid resource QC counting methodology. If, despite the concerns raised by CalCCA, the Commission adopts an interim methodology, it should clarify that the

---

12 *Id.* at 6.

13 *Id.*

methodology will not apply to Co-located Resources with two resource IDs, regardless of any resource restrictions, and clarify the meaning of "charging or operational restrictions."

Respectfully submitted,

Evelyn Kahl
Counsel to the
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

December 20, 2019

APPENDIX A

Proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs

New Findings of Fact:

6. Timely adoption of a permanent hybrid resource QC counting methodology for both IFM and BTM resources is critical to support continued development of these resources.

7. Co-located resources are two separate and distinct resources from the CAISO's viewpoint, and are treated as completely distinct resources for purpose of market participation, resource adequacy, settlements and other purposes.

8. It is unnecessary to impose restrictions on Co-located Resources at this time.

9. Hybrid resources are subject to "charging or operational restrictions" when a battery is required to be charged exclusively by the paired renewable resource to obtain Investment Tax Credits.

Conclusions of Law

5. SCE's definition of "charging" restriction should be used to determine when a hybrid resource is subject to charging or operational restrictions.

6. The PD's methodology will not be applied to Co-located Resources, even if the co-located resource has "charging or operational restrictions."

Ordering Paragraphs

4. For purposes of the interim qualifying capacity methodology, a hybrid resource is subject to charging or operational restrictions when a battery is required to be charged exclusively by the paired renewable resource to obtain Investment Tax Credits.

5. A permanent QC counting methodology for IFM and BTM hybrid resources shall be developed through a working group process, with the Joint Parties and SDG&E as co-leads, and shall be established in the June 2020 decision to be issued in D.19-11-009.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

OPENING COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON ORDER INSTITUTING RULEMAKING

Irene K. Moosen
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
415.587.7343
regulatory@cal-cca.org

Director, Regulatory Affairs
California Community Choice Association

Evelyn Kahl
Ann C. Springgate
Benjamin C. Ellis
Buchalter, A Professional Corporation
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
ekahl@buchalter.com

Counsel to the California
Community Choice Association

December 3, 2019

TABLE OF CONTENTS

TABLE OF ACRONYMS

BTM	Behind the Meter
CalCCA	California Community Choice Association
CCA	Community Choice Aggregator
D.	Decision
DR	Demand Response
ESP	Electric Service Provider
FERC	Federal Energy Regulatory Commission
IOU	Investor-Owned Utility
IRP	Integrated Resource Planning
LRA	Local Regulatory Authority
LCR	Local Capacity Requirement
LCTS	Local Capacity Technical Study
LSE	Load-Serving Entity
MUA	Multiple-Use Applications
NERC	North American Electric Reliability Corporation
OIR	Order Instituting Rulemaking
PG&E	Pacific Gas and Electric Company
R.	Rulemaking
RA	Resource Adequacy
RAR	Resource Adequacy Requirements
RA-CPE	Resource Adequacy-Central Procurement Entity
RMR	Reliability Must Run
SDG&E	San Diego Gas & Electric Company
WECC	Western Electricity Coordinating Counsel

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

OPENING COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON ORDER INSTITUTING RULEMAKING

The California Community Choice Association[1] submits these comments in response to the *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations* (OIR), issued on November 13, 2019, pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure and the directives provided by the OIR.

I. INTRODUCTION

CalCCA appreciates the opportunity to participate in this timely and critical reassessment of the Commission's RA program. Unanticipated and urgent directives from the Commission addressing system RA procurement, import RA eligibility criteria and other matters drive home the reality that the RA program has not kept up with the monumental changes in reliability requirements as the state moves aggressively toward its climate goals. CalCCA's comments thus

---

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

recommend that the Commission take a step back and develop clear objectives and guiding principles before embarking on this journey, including the following initial recommendations:

Principle #1: Resource adequacy rules should promote the development and retention of the fleet of resources needed to ensure reliable operation of the grid.

Principle #2: Resource adequacy rules should be robust, stable and durable and minimize regulatory uncertainty.

Principle #3: Resource adequacy rules should foster a competitive and efficient market that provides incentives for participants to achieve reliability goals and minimize costs to ratepayers.

Principle #4: Resource adequacy rules should apply equitably across LSEs.

Principle #5: Resource adequacy rules should establish performance requirements rather than mandate procurement of particular technologies.

CalCCA welcomes additional Commission and stakeholder input on the ultimate goals of this process to drive shared understanding and collaboration.

Additionally, these comments offer recommendations for areas to be considered in developing refinements, observing that all refinements—limited and "blue sky"—should be considered holistically and contemporaneously. CalCCA supports the OIR's identification of counting conventions and market power mitigation as issues that must be considered within the rulemaking's scope. In addition, CalCCA identifies the following areas of review:

- ✓ Methodology for Setting Resource Adequacy Requirements
- ✓ Mechanisms to Signal RA Requirements to the Market
- ✓ Clear and Stable Product Attributes and Eligibility Criteria for RA Compliance Products
- ✓ Multi-Use Applications Eligibility Criteria
- ✓ Import RA Availability and Eligibility
- ✓ Essential Reliability Resources and Effectiveness

Finally, CalCCA offers observations and recommendations to improve the process for establishing local and flexible RA obligations for the 2021 compliance year.

II. OBJECTIVES AND GUIDING PRINCIPLES

The Commission and stakeholders have an opportunity in this new rulemaking to step back from the intense detail of the rules stakeholders have debated over the past year and establish high-level principles before moving forward with changes to the existing RA program. The Commission should ground its next steps in an examination of the intended purpose of the RA program, with the aim of making that purpose transparent. Is the program intended solely to ensure there is electricity flowing at a reasonable price whenever a consumer flips the switch, or are there other objectives the Commission can legitimately pursue through the RA program? How will the RA program interact with the IRP process; for example, in which proceeding will the Commission address RA requirements, product eligibility criteria and the process for long-term procurement of the needed resources? How will the Commission interact with the CAISO in determining and fulfilling RA requirements and setting eligibility criteria? Answering these and other policy level questions will establish a solid foundation for further development of the RA program while minimizing disagreements arising from differences in understanding of the RA program's purpose or role.

In addition, the Commission should establish general principles to guide any changes in the design of the RA program. CalCCA initially recommends five guiding principles for the Commission's consideration, as follows.

Principle #1: ***Resource adequacy rules should promote the development and retention of the fleet of resources needed to ensure reliable operation of the grid.***

Resource Adequacy rules should embody a "no regrets" policy, ensuring through timely, forward-looking analysis that resources with the right characteristics are secured in the right place and at the right time to ensure load can be served consistent with NERC and CAISO reliability requirements and local regulatory authority reliability standards. The RA rules should be designed in close coordination with the CAISO and align with the CAISO tariff.

Principle #2: ***Resource adequacy rules should be stable and durable and minimize regulatory uncertainty.***

Resource Adequacy rules should aim to avoid frequent or sudden adjustments that disrupt the RA market while having sufficient flexibility to address reliability needs as they change over time. Stakeholders conducting long-term planning, whether for procurement or investment, should have confidence that RA rule changes will follow principles consistent with supporting reliability.

Principle #3: ***Resource adequacy rules should foster a competitive and efficient market that provides incentives for participants to achieve reliability goals and minimize costs to ratepayers.***

The RA rules should be designed to attract numerous buyers and sellers in the market, thereby enhancing liquidity and efficiency. Consistent with Principle #2, the rules should also specify clear and stable performance metrics that must be met by a resource to be eligible for compliance and accounting to inform product development in the market and minimize disputes.

Principle #4: ***Resource adequacy rules should apply equitably across LSEs.***

All LSEs—CCAs, ESPs and IOUs—should be required to secure RA, directly or indirectly, in proportion to their share of the contribution to the RA need as they change over time. The RA rules must also continue to maximize CCA procurement autonomy, as required by statute.[2]

---

[2] *See* CAL. PUB. UTIL. CODE §§ 366.2(a)(5), 380(b)(5) and 380(h)(5).

Principle #5: ***Resource adequacy rules should establish performance requirements rather than mandate procurement of particular technologies.***

The RA rules, in coordination with IRP requirements, should allow LSEs the flexibility to deploy their choice of technologies to meet performance criteria defined by the Commission in coordination with the CAISO. Mandating procurement in technology silos inhibits LSEs in deriving solutions that best meet reliability needs.

Framing the proceeding in these and other policy objectives and design principles will ensure that stakeholders embark in the rulemaking from a place of common understanding and purpose. The Commission thus should adopt objectives and guiding principles in the Scoping Memo.

III. SCOPE AND ISSUES FOR CONSIDERATION

A. Structural Changes to the RA Program

The OIR places potential changes in the RA program in two categories: "refinements" of existing rules and "structural changes."[3] While acknowledging the distinction between these categories of change, CalCCA recommends consideration of RA program changes—subtle or paradigm-shifting—holistically without phasing the discussion to consider each category separately. The RA program has undergone serial changes over the last few years, and these changes tend to create instability in the RA market and procurement planning. Considering all changes contemporaneously will avoid further market disruption, reduce the risk of rule changes to multi-year contracts, and allow the Commission and stakeholders to develop an integrated, durable solution. Critically, considering all potential changes together will also allow the

[3] *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations* (OIR), Nov. 13, 2019, at 3.

Commission to establish fair and reasonable transition measures to support reliability and the market as the program is refined.

Consistent with this approach, CalCCA recommends avoiding constraints on the scope of proposed changes to the RA program. Without constraints, stakeholders will be positioned to develop a broad range of potential changes to enhance reliability. If the Commission declines to adopt the proposed RA-CPE settlement advanced in R.17-09-020, CalCCA agrees that central buyer structures must, again, be considered. Even if the RA-CPE settlement is adopted as a starting place, other “blue sky” ideas at the November 1, 2019, workshop in R.17-09-020, should also be on the table to the extent they fall within the scope of this Commission’s jurisdiction. The merits of these and potentially other major structural changes should be compared with retaining a refined version of the existing RA program.

B. Refinement of the RA Program Elements

The OIR asks parties to identify up to ten areas of potential refinement to the existing RA program.[4] CalCCA agrees generally with the initial issues the OIR identifies and offers several additional topics for exploration.

The OIR identifies as central issues counting conventions for a variety of resource types, including ELCC calculations for solar, wind and hybrid resources.[5] CalCCA agrees that these issues should be considered and urges acceleration of calculations for hybrid resources; hybrid resources are a prime target for new procurement, and an understanding of those resources’ RA value is critical to encouraging development to meet the directives established in D.19-11-016.

---

4 *Id*. at 6.
5 *Id*. at 6-7.

This examination should also include stand-alone storage, multiple-use applications,[6] DR and BTM resources. Within the scope of counting conventions, the Commission should address the need for vintaging ELCCs or NQCs to mitigate the uncertainty and risk to LSEs in the medium- and long-term procurement processes.

The OIR also identifies "[m]arket power mitigation measures, including changes to the current penalty structure and waiver process for system, flexible and local RA."[7] CalCCA strongly agrees that these issues must be considered expeditiously to ensure that the Commission is fully exercising its responsibility for oversight of the IOUs' use of market power, particularly in local capacity areas. Market power mitigation is critical to prevent unnecessary ratepayer costs arising from RA compliance penalties. The Commission must respect the jurisdictional boundaries, however, between its proper role and the role delegated by Congress to FERC.

Beyond these preliminary issues identified in the ruling, CalCCA requests that the rulemaking's scope includes the issues identified below.

1. Methodology for Setting Resource Adequacy Requirements

The methodology for determining RA requirements is unsettled, as demonstrated recently in R.16-02-007, and should be updated after further study. The CAISO recently raised questions in its comments in R.16-02-007 regarding the need to reconsider the hours in which resource adequacy is assessed, observing the potential forward shift of the peak to "the hour ending 18"

---

6 Multiple-Use Application rules allow an energy storage unit to serve behind-the-meter load and to participate in CAISO energy markets and the RA capacity market. *See* D.18-01-003, Appendix A, Adopted Rules. The IOUs have claimed MUA RA value for their storage projects under Assembly Bill 2868 implementation. The Commission should clarify the application of these rules to ensure that all LSEs are equally available to claim the RA value of these projects.

7 OIR at 6.

by 2022.[8] The CAISO also raised the need to address sufficiency in post-peak periods when solar generation will be unavailable.[9] The CAISO continues its examination of local RA requirements, currently focused on its 2021 local capacity technical study,[10] and is redefining flexible RA criteria and must offer obligations through its Resource Adequacy Enhancements initiative.[11]

The success of the Commission's RA program depends foundationally on the ability of the Commission, in coordination with the CAISO, to determine the amount of RA required, when it is needed, and where it is needed with reasonable accuracy. The Commission should include in this rulemaking the goal of clarifying the methodology for determining local, system and flexible RA requirements.

2. Mechanisms to Signal RA Requirements to the Market

The June 20, 2019, ruling in the IRP sounded an alarm that LSEs were not procuring sufficient capacity to meet forward system RA needs. After a three-month review period, the ruling culminated in D.19-11-016, which directed LSEs collectively to procure 3,300 MW of "incremental" system RA by August 1, 2023,[12] and resolved to request extensions of retirement dates for once-through-cooling (OTC) generation.[13] This unanticipated and urgent action suggests a gap in not only determining the magnitude of RA requirements, but in communicating them to the LSEs responsible for procurement.

---

8 *Comments of the California Independent System Operator Corporation*, R.16-02-007, July 22, 2019, at 6.

9 *Id.* at 5.

10 *See* CAISO, *Local Capacity Requirement Process*, Study Manuals and Reports available at *http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx*

11 *See* CAISO, *INITIATIVE: Resource Adequacy Enhancements*, http://www.caiso.com/StakeholderProcesses/Resource-Adequacy-Enhancements

12 D.19-11-016, Conclusion of Law 9, at 74.

13 *Id.*, Ordering Paragraph 1, at 79-80.

The Commission should include in the scope of this rulemaking consideration of how RA requirements beyond one year, or even three years, are communicated to LSEs. The analysis should look to CAISO processes, the IRP and any other potential means of timely and reasonably signaling changing RA requirements to LSEs. In particular, if the Commission declines to adopt the RA-CPE settlement filed in R.17-09-020, which incorporates multi-year forward requirements, the Commission must consider modifying the existing framework to include multi-year system and flexible RA obligations to ensure proper signals are provided to LSEs for forward procurement of all types of RA.

3. Clear and Stable Product Attributes and Eligibility Criteria for RA Compliance Products

In conjunction with efforts to develop a reliable methodology to determine RA requirements, the Commission should also more directly define the performance characteristics a resource must provide to meet those requirements. The recent debate over the eligibility of import RA for compliance demonstrates the need for clear and stable product definition. As the Commission moves toward longer-term RA requirements, failure to provide clear and stable product definitions threatens market disruption, contract terminations or disputes, and a loss of value in existing RA commitments—which come at a high cost to ratepayers. The rulemaking thus should clearly identify the performance characteristics for each type of RA product and maintain a stable process for making any changes to these characteristics in the future.

4. Maximizing Opportunities for Resilience Co-Benefits

CalCCA anticipates significant investments on the part of CCAs, other LSEs, and individual customers in support of local energy resilience during Public Safety Power Shutoffs and other public safety emergencies. While current RA rules allow for some of these local and behind-the-meter resources to be utilized for both resilience and RA compliance, there are significant limitations, particularly for non-IOU LSEs, to utilize these investments for both purposes. CalCCA supports including in scope a review of the current opportunities and challenges for behind-the-meter resources to participate in RA consistent with the attributes and benefits they may offer for reliability. Given the influx of investment in BTM storage resources, CalCCA encourages the Commission to act swiftly to ensure these resources are installed and configured in such a manner as to maximize their contributions to system reliability under normal operating conditions.

5. Import RA Availability and Eligibility

Import RA has been under a microscope over the past few months, with the Commission's redefinition of eligibility requirements in D.19-10-021 and restrictions on counting import RA as "incremental" resources under D.19-11-016. CalCCA recommended several times in both proceedings that the Commission undertake an analysis of import RA availability and work with the CAISO to consider the value of these resources.[14] Imports are a vital resource in serving California's requirements, and the state must better understand their integration to ensure cost-effective reliability. The availability and effectiveness of import RA should be addressed within the scope of this rulemaking.

6. Essential Reliability Resources and Effectiveness

The Commission and Staff have raised concerns over the past few years regarding the need to understand and value the "effectiveness" provided by a resource in addressing local RA requirements. The rulemaking should examine the role and availability of "essential reliability

---

[14] *See, e.g., Application for Rehearing of Decision 19-10-021 of the California Community Choice Association*, October 24, 2019; *Comments of California Community Choice Association on Assigned Commissioner's Ruling Seeking Comment on Clarification to Resource Adequacy Import Rules*; *California Community Choice Association Comments on Revised Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023*, R.17-09-020, Oct. 31, 2019.

resources" in local capacity areas and the capabilities of the CAISO to forecast resource effectiveness. Armed with clear insights, the Commission and stakeholders will be positioned to more effectively assess how resource effectiveness should be factored into procurement and RA counting conventions.

C. Local and Flexible Procurement Obligations

As discussed in Section B, further definition of the methodology for determining requirements is needed for all RA, particularly to drive effective procurement of local and flexible resources. CalCCA offers three observations and recommendations regarding development of local and flexible RA procurement obligations for the Commission in approaching 2021 local and flexible RA requirements:

- ✓ Updated LCR criteria are expected to drive up the LCR needs in multiple locations and increase ratepayer costs;
- ✓ Assessment of local RA requirements would benefit from greater transparency in the CAISO's LCTS, including greater levels of detail from the CAISO on LCR area and sub-area hourly profiles; and
- ✓ The Commission should weigh-in on the appropriate reliability level for local RAR.

Each issue is discussed below.

1. Updated LCR Criteria Are Expected to Drive Up LCR Needs in Multiple Locations and Increase Costs

The CAISO provides its LCTS results to the Commission for consideration in setting annual local RA requirements. These results are also used by the CAISO for two purposes. First, they can be used to set the LCR, which is the minimum quantity of local capacity necessary to meet the LCTS criteria. Second, they can be used to allocate the costs of any CAISO local capacity procurement to address deficiencies remaining after LSE RA procurement and procurement of RMR resources.

Recently, the CAISO completed a stakeholder process that expanded the LCTS criteria to align them with the mandatory planning standards, which will result in increased LCR needs in several areas. Furthermore, there are certain LCR areas, where the LCR requirements are determined by higher-level contingencies, in which local resources may be procured even when they are not required to meet the mandatory reliability standards or to provide operational reliability. The Commission's rules must take these standards into consideration.

2. Local RA Assessment Would Benefit from Greater Transparency in the CAISO's LCTS

When D.18-06-030, which set local capacity obligations for 2019, adopted the CAISO's recommended 2019 LCR values, it did so with reservations and concerns.[15] Decision 18-06-030 notes complaints by SDG&E and PG&E about the lack of transparency involved in the LCR study assumptions and LCR results. In particular, it states:

> The fact that sophisticated LSEs such as PG&E and SDG&E are requesting additional transparency, and are having difficulty reproducing the CAISO's LCR results is in fact a problem that needs to be addressed going forward.[16]

CalCCA agrees. It is important to understand the assumptions involved in conducting the CAISO LCR studies, and CalCCA recommends that the CAISO provide greater transparency so that the assumptions can be revisited by all stakeholders.

3. More Detail from the CAISO on LCR Area and Sub-Area Hourly Profiles Would Better Inform Local Requirements

Beginning with the 2020 LCTS, the CAISO has enhanced its study process to include consideration of availability limitations such that CAISO can ensure sufficient energy (MWh) is available in addition to capacity (MW) in the LCAs. CalCCA supports the CAISO's plans to

---

15 *See* 18-06-030 at 9.

16 *Id.* at 7.

continue to include hourly load and available resource data within its existing LCTS reports going forward to guide resource procurement. Currently, the CAISO provides two plots for each LCR subarea and area—one comprising the representative Peak Day Forecast Profile and the other showing the hourly profile for the entire year.

CalCCA requests further transparency to enable better participation by stakeholders. First, the Commission should request that CAISO provide the underlying data in spreadsheet format for stakeholders to perform a deep-dive analysis. Second, the Commission should request that CAISO provide high-level guidance in terms of duration requirement for a local resource needed to reliably and adequately address the local requirements within each of the LCR sub-areas and areas. While the CAISO may not be able to perform as detailed analysis as they performed for the Moorpark Sub-Area,[17] a combination of the more detailed information provided under the annual LCTS and the LCR Reduction studies performed under the CAISO's 2018-2019[18] and 2019-2020[19] Transmission Plans should provide LSEs much-needed guidance in procuring local resources that meet the various sub-area and area LCR requirements.

4. The Commission Should Weigh In on the Appropriate Level of Local Reliability

Until recently, the CAISO's LCR results have been based on Reliability Performance Category C criteria, which has been driving significantly greater LCR needs than would have

---

[17] *See* CAISO, *Moorpark Sub-Area Local Capacity Alternative Study* (August 16, 2017), https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf

[18] CAISO, *Board-Approved CAISO 2018-2019 Transmission Plan* (March 29, 2019), http://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf

[19] CAISO, *Economic Assessment of Local Capacity Areas Extension of 2018-2019 Transmission Plan*, CAISO 2019-2020 TPP Stakeholder Meeting (September 25, 2019), http://www.caiso.com/Documents/Day1-Presentations-2019-2020TransmissionPlanningProcessMeeting-Sep25-26.pdf (at PDF 260/270).

resulted from the Category B criteria.[20] Decision 06-06-064, which addressed local capacity requirements for 2007, adopted Option 2, NERC Performance Category C criteria. It stated the following:

> Given the reduced risk of interruptions expected under Option 2, we consider the required procurement of an additional 5% of needed capacity to be reasonable. We make this reliability determination for 2007 only. While we expect to apply Option 2 in future years in the absence of compelling information demonstrating that the risks of a lesser reliability level can reasonably be assumed, we nevertheless leave for further consideration in this proceeding the appropriate reliability level for Local RAR for 2008 and beyond.[21]

Although D.06-06-064 anticipated that the reliability criteria determining the LCR levels would be revisited in the future, that has not happened. Given the likely increase in local capacity requirements associated with the expanded LCTS criteria to align with the mandatory planning standards discussed in Section III.C.1, the Commission should revisit its decision to apply the Category C vs. Category B criteria (or their Mandatory Reliability Standards equivalents[22]).

IV. PROCEDURAL MATTERS

A. Categorization

CalCCA agrees with the proposed categorization of this proceeding as ratemaking.

B. Process, Schedule and Need for Hearings

The OIR provides a skeletal outline for the review process, with one final decision in May 2020. While this schedule is reasonable for adopting the 2021-23 local and flexible RA requirements, it is wildly optimistic if the goal is to also consider refinements and "blue sky" paradigm shifts. Consequently, a separate, yet accelerated, track should be considered for these

---

20 The previous Reliability Performance Category criteria have been replaced by the Mandatory Reliability Standards.

21 D.06-06-064 at 19.

22 Category B is equivalent to P1, P2; Category C is equivalent to P3, P4, P5, P6 and P7.

broader purposes with the goal of implementing program refinements for the 2022 compliance year.

Track 2 issues would best be developed through a comment and workshop process, in which all "refinements" and "blue sky" proposals are advanced. These proposals, however, would be most effective if informed by common analysis. CalCCA thus requests that the Commission Staff, in coordination with the CAISO, present quantitative analysis on critical issues prior to solicitation of proposals from Staff and other stakeholders. In particular, the analyses should study the following issues:

- The shift in peak hours over the next five years;
- The relationship of peak hours and post-peak hours over this period;
- A comparison of the availability of various resource types over the forecasted peak and post-peak periods;
- The availability of import RA based on supply/demand conditions in the WECC; and
- Historical performance of import RA in the CAISO markets.

While the CAISO has already begun to examine several of these issues, the Commission should coordinate with the CAISO to refine these analyses and make them transparent for consideration in this rulemaking.

It is unclear at this point whether hearings will be required. The schedule should provide an opportunity to request hearings following a substantive exploration of the issues.

V. CONCLUSION

For all of the foregoing reasons, CalCCA requests that the Assigned Commissioner and Administrative Law Judge adopt a scope for this rulemaking that includes all of the issues identified herein.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl

Counsel to the California
Community Choice Association

December 3, 2019

JANUARY FILINGS

Stakeholder Comments Template

Hybrid Resources Initiative: Straw Proposal

This template has been created for submission of stakeholder comments on the **Hybrid Resources Initiative, Revised Straw Proposal** that was held on December 17, 2019. The meeting material and other information related to this initiative may be found on the initiative webpage at: http://www.caiso.com/informed/Pages/StakeholderProcesses/HybridResources.aspx

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on January 14, 2019**.**

Submitted by	Organization	Date Submitted
Irene Moosen, 415-587-7343	California Community Choice Association[1]	*January 14, 2020*

Please provide your organization's comments on the following topics and indicate your orginzation's position on the topics below (Support, Support with caveats, Oppose, or Oppose with caveats). Please provide examples and support for your positions in your responses as applicable.

1. Terms and Definitions

Please provide your organization's feedback on the proposed terminology and defintions as described in the revised straw proposal.

CalCCA supports CAISO's proposed updated definition of Hybrid Resource:

> "A resource type comprised of a mixed-fuel type project, or a combination of multiple different generation technologies that are physically and electronically controlled by a single owner/operator and Scheduling Coordinator behind a single point of interconnection ("POI") that participates in the CAISO markets as a single resource with a single market resource ID."

CalCCA supports CAISO's proposal to require that Hybrid Resources meet the minimum sizing requirements for both of the underlying generation components: 500kw for any participating generator hybrid resource component and 100kw for any storage hybrid resource components. CalCCA suggests, however, that there may be circumstances that warrant deviations from these amounts and that CAISO should grant waivers in instances when it would not be unduly burdensome for CAISO to accommodate them.

CalCCA supports CAISO's proposal to treat Co-located Resources (i.e., projects with two or more resource IDs with a common point of interconnection) as distinct resources for purposes of market participation, with the exception of coordination of dispatch and operations to limit output to the project's interconnection rights, and with the ability to track the use of co-located storage by the co-located VERs and described further in the metering and telemetry section.

2. Forecasting

Please provide your organization's feedback on the forecasting topic as described in the straw proposal.

CalCCA supports CAISO's proposal to provide forecasting for Variable Energy Resource (VER) component of both Co-located and Hybrid Resources. CalCCA appreciates CAISO's responsiveness to stakeholders' request that CAISO offer forecasting services for the VER component of Hybrid Resources.

3. Markets and Systems

Please provide your organization's feedback on the markets and systems topic as described in the revised straw proposal.

CalCCA requests that the ability to change a VERS bid closer to real time be applied to the VERS Hybrid resource in the same manner as now applies to colocated VERS resources. CalCCA is concerned that not allowing a Hybrid VERS forecast to be updated closer to real time in the same manner as colocated VERS resources (with two resource IDs) unfairly burdens the Hybrid resource with higher risk of deviations. When CAISO introduced the 15 minute market and improved the timing of 5-minute forecasts for VERS in its FERC 764 initiative, it actually made a huge improvement to forecasting for VERS. What is being proposed by CAISO here for Hybrid resources could be a step back.

CalCCA supports CAISO's clarification in Table 2 that the storage associated with both hybrid resources and co-located resources will be able to have the storage charged from i. the on-site generation, ii. charged from the grid via bids and CAISO dispatch, or iii. charged from both on-site generation and the grid via bids and CAISO dispatch.

CalCCA supports the CAISO proposal to develop a new interconnection rights constraint that ensures co-located resources' outputs remain less than or equal to the co-located project's maximum POI injection rights without stranding capacity from either of the co-located resource IDs. CalCCA supports CAISO's plan to implement this functionality for energy market participation by Fall 2020, and for ancillary services market participation by Fall 2021, with the option for resource owners desiring to participate in ancillary service markets prior to Fall 2021 to either limit their combined Pmax to the total interconnection rights or to select the hybrid resource option.

4. Ancillary Services

Please provide your organization's feedback on the ancillary services topic as described in the revised straw proposal.

CalCCA supports the use of the 5-minute VER forecast to determine the High Sustainable Limit (i.e., the maximum output capability of the VER component of a hybrid resource) for the VER portion of Hybrid Resources. This can then be used in conjunction with the storage resource state of charge and charging/discharging status to determine the A/S potential for Hybrid Resources.

5. Metering and Telemtry

Please provide your organization's feedback on the metering and telemetry topic as described in the revised straw proposal.

CalCCA appreciates the CAISO's proposal to allow for an additional metering configuration to mitigate potential settlements impacts and concerns regarding ITC eligibility and other undesirable financial impacts for co-located resourcs by requiring a third meter be installed for these co-located resources that wish to select the option to charge from on-site generation. The CAISO will use the three associated meters to perform logical metering calculations that will reflect the fact that the co-located storage resource is charging from on-site generation. During the December 17 stakeholder meeting, some parties noted that it should be possible to perform the described logical metering calculations with only two meters. CalCCA supports exploring both approaches in case resource owners determine it is not necessary to install three meters to maintain ITC eligibility.

CalCCA seeks confirmation from CAISO that gas hybrid resources would have the option to install multiple meters to facilitate tracking of the emissions reduction benefits associated with utilization of the hybrid resource components. These hybrid resources could facilitate significant GHG emissions reductions while supporting reliable grid operations and it is important that the benefits be documented.

CalCCA reiterates its request that CAISO continue to facilitate certification of DC meters to provide the greatest amount of flexibility and enhanced visibility of the various components of Hybrid Resources and Co-located Resources.

6. Resource Adequacy

Please provide your organization's position on the Resource Adequacy topic as described in the revised straw proposal.

CalCCA supports the CAISO proposal to apply the current counting rules for the individual components of co-located resources with a common POI. For co-located resources whose aggregate components exceed the POI rights, CalCCA supports the CAISO working with resource interconnection customers to split and limit the component QC values to ensure the POI limits are not exceeded.

CalCCA opposes CAISO's proposal to adopt the interim QC methodology for hybrid resources in the CPUC Proposed Decision that would limit the QC to the greater of the individual component resources' QC. CAISO's previous proposal to sum the individual component resource QCs would better reflect the expected contribution of hybrid resources. As an initial matter, the CPUC Proposed Decision has not yet been adopted. As CalCCA noted in its comments to the CPUC, the Proposed Decision's approach is uninformed by a full exploration of reasonable alternatives, lacks the clarity necessary for successful implementation and risks shortchanging the value of hybrid resources.[1] Devaluing hybrid resources to a very conservative solution without adequate exploration of alternatives, particularly at a time when these resources are increasingly viewed as the key strategy for system reliability, would be counterproductive. The proposed methodology would effectively eliminate the resource adequacy (RA) value of either the Variable Energy Resource component or the storage component of hybrid resources for portions of the year. This would present a significant barrier for LSEs seeking to urgently develop these resources in line with near-term needs identified by the Commission in D.19-11-021. Unless and until CAISO performs analysis demonstrating the detrimental impacts on expected capacity due to interactions between hybrid resource components, it should stick with its previous proposal to sum the component resource QCs. At most, the "greater of" approach should only be applied to hybrid resources that require the associated storage be charged exclusively from the paired renewable resource to obtain the ITC.

Additional comments

Please offer any other feedback your organization would like to provide on the Hybrid Resources Initiative.

[1] COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION GRANTING MOTION REGARDING QUALIFYING CAPACITY VALUE OF HYBRID RESOURCES WITH MODIFICATIONS found here: https://cal-cca.org/wp-content/uploads/2019/12/R.17-09-020-CalCCA-Comments-on-Proposed-Decision-Granting-Motion.pdf

Stakeholder Comments Template

Resource Adequacy Enhancements

This template has been created for submission of stakeholder comments on the Resource Adequacy Enhancements third revised straw proposal that was published on December 20, 2019*.* The proposal, stakeholder meeting presentation, and other information related to this initiative may be found on the initiative webpage at: http://www.caiso.com/StakeholderProcesses/Resource-Adequacy-Enhancements

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on **January 27, 2020**.

Submitted by	Organization	Date Submitted
Evelyn Kahl, Buchalter (415) 227-3563	California Community Choice Association[1]	*January 27, 2020*

Please provide your organization's comments on the following issues and questions.

1. System Resource Adequacy

Please provide your organization's feedback on the System Resource Adequacy topic as described in section 5.1. Please explain your rationale and include examples if applicable.

CalCCA is primarily concerned with ensuring that the Resource Adequacy (RA) rules correctly quantify the reliability contribution of capacity based on its actual expected availability when needed. CalCCA believes this can be achieved through the CAISO's proposed UCAP methodology, though it is critical that the correct data are used to accurately derive such demonstrably predictive values, and properly differentiate among resource technologies, vintages, locations, environments, operating restrictions, fuel sources, and other relevant and potentially unique factors.

---

[1] California Community Choice Association represents local government Community Choice Aggregation electricity providers in California members, including Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, East Bay Community Energy, King City Community Power, Lancaster Choice Energy, MCE, Monterey Bay Community Power, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy.

CalCCA maintains its concern regarding UCAP calculations based on daily outage data. If a resource has a very brief outage anytime during the operating day, this would count as a full day of outage (for the portion of the capacity that is out) in the current proposal. Since some outages last less than a full day, the data reviewed to-date may overstate the actual frequency of forced outages. The CAISO must ensure that the data used to set the UCAP requirements accurately represents actual forced outages for individual resources and each class of resources.

If the CAISO moves forward with a UCAP methodology, CalCCA believes that it is important for the CAISO to conduct analysis on circumstances that created the dataset of forced outage and derate events, in order to identify patterns and ensure that the calculation is the best possible reflection of expected future performance. If an historical dataset of forced outages and derates demonstrates that these events occur according to identifiable patterns, then such patterns should inform the implied weight each event is given to ensure UCAP is, to the greatest degree possible, an unbiased predictor of future events. CalCCA therefore strongly urges the CAISO to continually revisit the UCAP calculation inputs and assumptions as it gains experience with the new market structure.

CalCCA is also concerned with the arbitrary selection of only 100 hours in each of two seasons for use in UCAP calculations. An unintended consequence is that a resource's UCAP could be disproportionately impacted by unfortunate random chance with little predictive value for future performance. Parties may then be motivated to show RA resources with artificially high UCAP values and avoid resources with artificially low UCAP values, thereby unnecessarily skewing the pool of RA resources. CalCCA encourages the CAISO to use a larger selection of hours, and identify in a compelling manner with supporting analysis why an all-hour (8,760) dataset is not appropriate.

On the topic of outages, CalCCA appreciates the CAISO's objective to minimize cancellation of planned outages, and to minimize the need for substitution of capacity. In the present proposal, the CAISO notes:

> *"In comments, CalCCA expressed concerns that the CAISO's proposal would result in incentives to withhold capacity instead of making the capacity readily available to the market. The CAISO notes that the shift to UCAP counting rules, above, will significantly mitigate the incentive to withhold capacity from the bilateral capacity market. This aspect of the CAISO proposal may result in an LSE holding capacity for replacement purposes. <u>Any opportunity or requirement for replacement capacity will create some level of withholding incentive</u>. Here the CAISO attempts to balance this incentive with allowing some flexibility to resource SC to plan outages as needed. However, given the other incentives and information provided in the CAISO's proposal, this risk is likely reduced to the lowest point possible." (<u>emphasis</u> added)*

CalCCA encourages the CAISO to eliminate entirely the potential for capacity withholding under the auspices of an LSE's attempts to manage risks related to substitution requirements for planned outages. Capacity shortfalls due to changed circumstances after an outage has been scheduled should be a risk that is pooled.

Any potential obligation to provide substitute capacity provides an opportunity for withholding. The CAISO is best-suited to both i) minimize the chance of such a situation occurring (through improved outage planning processes and potentially incorporating an expectation of planned outages into the RA requirements setting process), and ii) backstop procurement in case such rare events do occur. Leaving the CAISO with the responsibility for coordinating replacement/substitute capacity is also better aligned with the Central Buyer framework proposed by settling parties in the CPUC proceeding R.17-09-020.

CalCCA appreciates the CAISO's treatment in the Third Revised Straw Proposal of factors to use to appropriately set the System Resource Adequacy UCAP requirement, accounting for peak demand, reserves, forced outages, and potentially forecast error. CalCCA is generally supportive of the approach described by the CAISO. As mentioned above, CalCCA also encourages the CAISO and stakeholders to consider inclusion of expected planned outages in the RA requirements setting process, in parallel with efforts to improve the outage planning process. Together, these changes could eliminate circumstances that today contribute to declined planned outages, which CalCCA would like to see eliminated. CalCCA above all encourages the CAISO to continually monitor performance of the new rules post-implementation, and to seek to involve stakeholders where improvements are identified, in order to ensure that the rules are achieving the clearly stated program objectives. Issues for continuous evaluation could include:

- The number of hours in the year used for UCAP calculation (the optimal number is unknown, but CalCCA believes 100 hours for each of two seasons is too low).
- Rules for collection of more detail data to support analysis of patterns in outages (planned and forced).
- Consideration of an intermediate category of scheduled outage 7 days or fewer before the outage itself, one which cannot be cancelled, and which impacts UCAP at less than unity (a "mandatory scheduled outage"); a short-term scheduled but necessary outage should be proportionately incorporated into the UCAP calculations, acknowledging the reduction in reliability impacts resulting from any advance notice at all compared with a post-contingency or post-emergency forced outage.
- Alignment of the RA rule treatment across technology types, including especially hybrid resources as their presence in the supply fleet grows.

Please provide your organization's position on the System Resource Adequacy topic as described in section 5.1. (Please indicate Support, Support with caveats, Oppose, or Oppose with caveats)

CalCCA supports the CAISO's proposal with caveats described above and calls the CAISO's attention to the fact that the proposal is not the only solution to the issues identified in this stakeholder process, but that these issues have been discussed extensively in forums including the Central Buyer settlement proposal crafted among a diverse set of stakeholders in R.17-09-020.

2. Flexible Resource Adequacy

Please provide your organization's feedback on the Flexible Resource Adequacy topic as described in section 5.2. Please explain your rationale and include examples if applicable.

CalCCA agrees that the flexibility needed to meet the unpredictable flexible capacity needs should align with the proposed Imbalance Reserves market mechanism as proposed and that the predictable flexible capacity needs[2] will be achieved through the resource planning efforts of LSEs. CalCCA agrees with the CAISO's expressed reasoning in Section 5.2.1 that LSE's procurement of capacity with the capability to meet the CAISO's predictable net ramps should, and will, be conducted by such LSE considering trade-offs among cost, ramp rate, and portfolio content obligations and targets.

Please provide your organization's position on the Flexible Resource Adequacy topic as described in section 5.2. (Please indicate Support, Support with caveats, Oppose, or Oppose with caveats)

In the near term, CalCCA supports the CAISO's efforts to align Flexible Resource Adequacy rules with the proposed Imbalance Reserves market mechanism and to eliminate the 3 hour net ramp method of calculation.

In the long-run, however, the CAISO should consider eliminating the Flexible Resource Adequacy rules entirely. Doing so could reduce the complexity of the RA requirements greatly without having a material impact on the characteristics of the fleet of resources being procured by market participants. If the resource fleet systemwide evolves to a state of surplus flexibility and the Imbalance Reserves market mechanism demonstrates that such a spot market solution for covering unpredictable flexible capacity needs is sufficient to support system reliability, this would suggest a Flexible Resource Adequacy product is unnecessary.

3. Local Resource Adequacy

Please provide your organization's feedback on the Local Resource Adequacy topic as described in section 5.3. Please explain your rationale and include examples if applicable.

CalCCA appreciates the CAISO's responsiveness to stakeholder comments as it further refines the Local RA rules and continues to support the UCAP method for Local Resource Adequacy. Any approach to local RA (whether NQC or UCAP) will be complex, and this is an artifact of the generally complex nature of local capacity

[2] Section 5.2.1 of Resource Adequacy Enhancements – Third Revised Straw Proposal at page 70.

evaluation (treatment of effectiveness factors in other forums demonstrate this to be true). Applying the UCAP approach to local RA will address the resource substitution-related issues described above in the system RA discussion (with CalCCA's proposed modifications to the maintenance outage process). It is important to recognize that the current pool of available local resources is limited and already constrained both by resources' effectiveness factors and their forced outage rates. As new resources are added, incorporating forced outage rates into the local RA evaluation will incentivize increased reliability.

CalCCA encourages the CAISO to consider how its rules will facilitate the evolution of the resource fleet and count the reliability contribution of locally developed storage and supply resources in import-constrained areas, especially in light of the growing interest and implementation of microgrids and distributed energy resiliency systems. CalCCA strongly encourages CAISO to continually monitor RA rules to ensure that resources' contribution to reliability are properly and appropriately quantified, accounting for scale, location, technology, operating parameters, and other factors.

Please provide your organization's position on the Local Resource Adequacy topic as described in section 5.3. (Please indicate Support, Support with caveats, Oppose, or Oppose with caveats)

CalCCA supports the CAISO's proposal, subject to its proposal to eliminate maintenance outage substitution requirements as described in Section 1.

4. Backstop Capacity Procurement Provisions

Please provide your organization's feedback on the Backstop Capacity Procurement Provisions topic as described in section 5.4. Please explain your rationale and include examples if applicable.

CalCCA supports CAISO's proposed new authority to make CPM designations to address deficiencies identified by the proposed portfolio analysis. As CAISO has shown, considering only the single peak hour each month may not result in CAISO having access to sufficient RA resources to serve load, particularly during the hours immediately following the peak hour. It is reasonable for CAISO to have backstop procurement authority to address the identified deficiencies. CalCCA encourages CAISO to provide market participants detailed information about the backstop studies it intends to run, including key study assumptions and potentially access to study tools, and to perform similar studies as it participates in the CPUC IRP proceedings, to inform parties' procurement decisions and to reduce the likelihood that CAISO will have to exercise its expanded backstop authority.

CalCCA opposes CAISO's proposed new tool to encourage load to procure resources up to full UCAP requirements and dis-incentivize entities from leaning on other LSEs. As stated in CalCCA's comments on the second revised straw proposal:

CalCCA opposes the proposed LSE RA showing incentive, in which CAISO would charge short LSEs a penalty and distribute collected proceeds to long LSEs. We are concerned that such penalties could distort the bilateral RA markets, particularly in cases where suppliers have market power. Parties that fail to meet their RA requirements will be at risk of being allocated CAISO backstop procurement costs resulting from their deficiencies, in addition to being exposed to potentially high energy market prices. CalCCA also notes that if the RA-CPE proposal supported by CalCCA is implemented, all of the CPUC jurisdictional LSE RA requirements would be met on a three year forward basis by individual LSEs and the RA-CPE without any penalty structure.

Please provide your organization's position on the Backstop Capacity Procurement Provisions topic as described in section 5.4. (Please indicate Support, Support with caveats, Oppose, or Oppose with caveats)

CalCCA supports and opposes elements of the Backstop Capacity Procurement proposal as described above.

Additional comments

Please offer any other feedback your organization would like to provide on the Resource Adequacy Enhancements third revised straw proposal.

CalCCA appreciates CAISO's attention to the issue of integrating storage resources into the resource fleet to facilitate a smooth transition to a clean energy future while maintaining reliability and potentially resolving local transmission issues.[3] CalCCA additionally understands and appreciates the unique risk posed by heavy reliance on storage resources; this strategy could potentially leave the CAISO with insufficient energy available to meet net peak demand, which is expected to occur late in each operating day. The task for the CAISO and stakeholders is to improve overall system efficiency *and* reliability by striking the proper balance between i) providing the CAISO confidence that storage resources will have enough energy stored when needed to maintain reliability, and ii) allowing enough real-time flexibility to capture the unique advantages of storage resources to shift energy from low-value periods to high-value periods and to respond quickly to changing conditions.

The CAISO's primary concern is that a storage resource that clears the Day-Ahead Market with a charge and discharge schedule may be unable to meet this schedule in real-time. The concern arises because a storage resource must first charge (withdraw energy from the grid) in order to store energy for discharge (injection of energy to the grid) at a later time. This could happen if the 5-minute Real-Time Dispatch economically dispatches the resource to forego charging or to discharge in a way that deviates from the DAM schedule, or if the resource operator self-schedules the resource to the same effect. The CAISO's proposed solution -- a minimum state of

[3] Section 5.1.7 of Resource Adequacy Enhancements – Third Revised Straw Proposal at page 60.

charge (SOC) constraint on storage resources – could ensure that the resources begin a discharge period of their daily cycle with enough energy stored to meet the full energy needed for the scheduled discharge in the DAM schedule.

Alternatives also proposed and dismissed were to mandate that storage resources adhere to their DAM schedules, or to extend the look-ahead horizon for the Real-Time Market in order to generate feasible dispatch schedules that ensured sufficient energy is stored to meet the energy needs during the anticipated discharge periods (generally beginning in the early evening when solar generation is ramping down).

CalCCA appreciates that the straw proposal is still in draft form and substantive details are yet to be fleshed out, but nonetheless has several concerns regarding the storage proposal:

1. The proposal language is ambiguous and suggests that the minimum SOC constraint could be enforced early in the day, perhaps as early as the start of the day (12:01 AM), to guarantee that the DAM discharge schedule can be met.
    a. CalCCA Concern: Enforcing the constraint in this way would disallow multiple full or partial charge-discharge cycles in a day, and would preclude storage resources from responding to real-time market signals of surplus and scarcity.
2. The proposal does not address the disincentives that result from limiting storage resources with a DAM schedule from realizing potential real-time value.
    a. First CalCCA Concern: Storage resource operators may be incentivized to submit offers in order to avoid clearing the DAM, and avoid the constraint otherwise imposed on them, that is not imposed on other types of resources. This unintentional side effect could thwart the described intent of the constraint, and result in a less efficient outcome than if no constraint were implemented at all.
    b. Second CalCCA Concern: Inadvertently limiting participation in the DAM (by incentivizing storage resources to only participate in real-time) may force the CAISO to guess if and how storage resources will participate in the Real-Time Market, increasing uncertainty.
    c. Third CalCCA Concern: Behavior to avoid a DAM schedule (which could be a predictable and even understandable result of this proposal) may be difficult to discern from behavior considered to be unjustified withholding under market power rules, and may complicate efforts to assess and mitigate exercises of market power.
3. The proposal is not clear on the enforcement mechanism for the minimum SOC constraint. Without a specific incentive structure beyond positive uninstructed imbalance energy settlements, the constraint would have no impact.

CalCCA proposes the following list of items for consideration:

1. Reconsider a variation of the CAISO's third proposal (extension of the RTM horizon beyond 65 minutes) in this or a separate stakeholder process in order to optimize storage resources' real-time schedules several hours into the future.

Such a market run could be performed in advance of, and then in parallel with, the 5-minute Real-Time Dispatch optimization, but less frequently than every 5 minutes, considering the non-linear growth in problem complexity with a longer look-ahead. The results of this market run, which would optimize storage resources over a much longer horizon (several hours) could help optimize dispatch schedules to meet real-time conditions more efficiently than the current proposal, while maintaining the CAISO's need for reliable late-day energy supply.

2. If a minimum SOC is instituted, enforce the constraint only at the beginning of any discharge event (single or multiple hour) in the resource's DAM schedule. Note that this would support multiple cycles in a day and allow resources to provide real-time flexibility and value that aligns with the storage resource's full capabilities.
3. Consider postponing any proposal specifying disparate treatment of storage resources in the real-time markets and waiting to reevaluate such a proposal as the CAISO gains greater experience with storage resources reaching commercial operation over the next several years.
4. Finally, CalCCA encourages the CAISO to consider enforcing a minimum SOC (or other mechanism) only on a subset of storage resources. These could be selected by merit order based on minimized expected foregone real-time net revenues. For example, storage resources could supplement their DAM bids with an expectation of foregone real-time revenues ($/MW-day) that would result from being subject to such a constraint. The CAISO would enforce the constraint on resources in merit order (lowest foregone revenue to highest) until enough[4] MWh were selected.

All elements of the new RA rules should be continually evaluated to ensure that they are effectively solving a clearly identified set of problems in line with clearly expressed principles.

[4] Based on CAISO experience and analysis, much like the analytical mechanism that will be used to derive the Imbalance Reserve quantity.

January 6, 2020

CPUC, Energy Division
EDTariffUnit
505 Van Ness Ave., 4th Floor
San Francisco, CA 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

Southern California Gas Company
Ray Ortiz
Tariff Manager – GT14D6
555 West Fifth Street
Los Angeles, CA 90013-1011
E-mail: rortiz@socalgas.com

Center for Sustainable Energy
Sephra A. Ninow, J.D
Director, Regulatory Affairs
Center for Sustainable Energy
3980 Sherman Street, Suite 170
San Diego, CA 92110
E-mail: sephra.ninow@energycenter.org

Southern California Edison Company
Attn: Gary A Stern, PhD
Managing Director, State Regulatory Operations
8631 Rush Street
Rosemead, CA 91770
E-mail: AdviceTariffManager@sce.com

Attn: Laura Genao
Managing Director, State Regulatory Affairs
c/o Karyn Gansecki
601 Van Ness Avenue, Suite 2030
San Francisco, CA 94102
E-mail: Karyn.Gansecki@sce.com

Re: **Response of Marin Clean Energy to Pacific Gas and Electric Company Advice Letter 4191-G/5714-E, Southern California Edison Company Advice Letter 4127-E, Southern California Gas Company Advice Letter 5555-G, and Center for Sustainable Energy Advice Letter 106-E (Proposed Revision to the Self-Generation Incentive Program Handbook to Incorporate a New Equity Resiliency Budget for Residential Customers (Systems $\leq$ 10kW) Including Changes to Incentive Structures, Program Requirements, Marketing Education and Outreach Plan, and Budget Allocations Pursuant to Decision 19-09-027)**

Dear Tariff Unit and Mr. Randolph:

Pursuant to Section 7.4 of California Public Utility Commission ("Commission") General Order ("GO") 96-B, Marin Clean Energy ("MCE")[1] submits this response to Pacific Gas and Electric Company Advice Letter 4191-G/5714-E, Southern California Edison Company Advice Letter 4127-E, Southern California Gas Company Advice Letter 5555-G, and Center for Sustainable Energy Advice Letter 106-E, *Proposed Revision to the Self-Generation Incentive Program Handbook to Incorporate a New Equity Resiliency Budget for Residential Customers (Systems ≤ 10kW) Including Changes to Incentive Structures, Program Requirements, Marketing Education and Outreach Plan, and Budget Allocations Pursuant to Decision 19-09-027* ("Joint SGIP PA Advice Letter"), submitted on December 17, 2019.

MCE is submitting a limited response on the Advice Letter, focusing on the issue of the new Marketing, Education and Outreach ("ME&O") plan for the Self-Generation Incentive Program's ("SGIP") equity budget.

I. BACKGROUND AND INTRODUCTION

The SGIP was established in 2001 by the Commission in Decision (D.) 01-03-073 in response to Assembly Bill ("AB") 970. In 2017, the Commission established the SGIP Equity budget to facilitate program participation for low-income customers and non-profit or public sector organizations in disadvantaged or low-income communities.[2]

As there were no subscriptions in the SGIP equity budget between 2017 and the summer of 2019, the Commission published D.19-09-027 in September 2019 to modify equity budget program requirements and incentive levels to increase participation.[3] Most notably, the Commission established a new equity resiliency budget for vulnerable households located in Tier 3 and Tier 2 high fire threat districts ("HFTDs"), critical facilities serving those districts, and

[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 serving approximately 1,000 MW peak load, providing electricity generation services to more than 1.1 million people in 34 communities across Marin, Contra Costa, Napa, and Solano counties.
[2] D.17-10-004, *Decision Establishing Equity Budget for Self-Generation Incentive Program*, from October 12, 2017.
[3] D.19-09-027, *Decision Establishing a Self-Generation Incentive Program Equity Resiliency Budget, Modifying Existing Equity Budget Incentives, Approving Carry-over of Accumulated Unspent Funds, and Approving $10 Million to Support the San Joaquin Valley Disadvantaged Community Pilot Projects*, from September 18, 2019.

customers located in those districts that have participated in low-income solar programs. D.19-09-027 also directed the SGIP Program Administrators ("PAs") to develop a customized equity budget ME&O plan ("Equity ME&O Plan") to rapidly inform eligible customers with the greatest resiliency needs about the availability of SGIP incentives. Local governments and Community Choice Aggregators ("CCAs") were identified as potential partners in the implementation of the Equity ME&O Plan.[4]

MCE has been in conversations with PG&E, GRID Alternatives,[5] and other stakeholders about developing a joint effort under the SGIP Equity ME&O Plan to enable an accelerated and effective outreach campaign to eligible customers and support the installation of behind-the-meter energy storage solutions before the next fire season. However, due to limited time, stakeholders were not able to coordinate on the filing of a joint Equity ME&O Plan for residential customers. Instead, the SGIP PAs put forward a high-level, statewide approach for a residential Equity ME&O Plan in an Advice Letter on December 17, 2019 to which MCE now responds.

MCE supports the statewide approach as proposed by the SGIP PAs for a high-level, mass-market ME&O campaign to inform residential customers about the availability of SGIP incentives. MCE also appreciates the SGIP PAs' proposal to work collaboratively with stakeholders on a comprehensive Equity ME&O Plan to be filed by February 18, 2020[6] and is looking forward to working with PG&E and other stakeholders in developing such a plan via workshops in January 2020.

However, MCE cautions that ME&O strategies proposed by the SGIP PAs to date will not suffice in reaching vulnerable customers with the greatest resiliency needs before the next fire season. Therefore, MCE strongly recommends that the SGIP PAs' high-level statewide approach for an Equity ME&O Plan is complemented by a highly targeted, on-the-ground community outreach campaign implemented by CCAs and other community stakeholders. MCE is submitting a "*Community Outreach Plan for the Self-Generation Incentive Program's Equity and Equity*

[4] D.19-09-027 at 58

[5] GRID Alternatives is the Program Administrator for the low-income solar programs SASH, DAC SASH and is part of the PA team for the SOMAH program

[6] See *Joint Request by Self-Generation Incentive Program (SGIP) Program Administrators (PAs) in accordance with CPUC Rule of Practice and Procedure 16.6 for an Extension of Time to Submit Some of the Requirements pursuant to Ordering Paragraph 7 of Decision (D.)19-09-027,* sent via email on December 5, 2019.

Resiliency Budget for Residential Customers" ("MCE Community Outreach Plan") in Appendix A of this response. In Appendix B, MCE is submitting letters of support from local partners.

MCE stands ready now to begin an intensive and highly targeted community outreach effort under the SGIP Equity ME&O Plan and submits the following specific recommendations to the Commission in this response:

a. The Commission should *require* the SGIP PAs to work with CCAs in the development of a comprehensive SGIP Equity ME&O Plan
b. CCAs should be given the opportunity to become the local community outreach partner under the SGIP Equity ME&O Plan in their service area.
c. The Commission should approve MCE's Community Outreach Plan for the SGIP Equity and Equity Resiliency Budget for Residential Customers as attached to this response.
d. The Commission must make the appropriate funding available for community outreach partners under the SGIP Equity ME&O Plan

II. DISCUSSION AND RECOMMENDATIONS

MCE applauds the Commission's initiative to create the SGIP Equity ME&O Plan, recognizing the importance of not only making incentives available to customers, but also ensuring that customers are aware of such incentives and can access them effectively and efficiently. Experience under the SGIP equity budget to date has shown that without a dedicated and appropriately funded marketing, education and outreach campaign, recruitment of vulnerable customers for program participation is challenging.

MCE supports the statewide approach as proposed by the SGIP PAs for a high-level, mass-market ME&O campaign but adds the following recommendations to enhance the effectiveness of the outreach campaign.

A. CCAs, as local government partners, are integral components of a community outreach strategy under the Equity ME&O Plan and the Commission should *require* the SGIP PAs to work with CCA in the development of a comprehensive SGIP Equity ME&O Plan by February 18, 2020.

MCE is a community-based and customer-focused public agency serving 34 communities across Marin, Napa, Contra Costa, and Solano counties. MCE serves a significant population of approximately 83,000 low-income and medically-impacted[7] customer accounts, as well as another 40,000 customer accounts located in disadvantaged communities. MCE's service area includes many Tier 3 and Tier 2 HFTDs; approximately 35% of MCE's customer base of 470,000 customer accounts have experienced public safety power shutoffs ("PSPS") to date.

MCE was founded on the principles of community choice and participation. Community partnerships, engagement, and outreach are key elements of MCE's energy services and program delivery model and are integral to MCE's success. Since its inception, MCE has established relationships with local community-based organizations ("CBOs") and local government agencies that support these communities. CBOs are an active channel of communication from MCE to its communities, as well as bringing the voice of the community into MCE. Additionally, MCE has developed and successfully implemented a number of programs targeted at income qualified and disadvantaged communities, including programs for solar, electric vehicles and energy efficiency.

Most recently, MCE has put significant efforts towards improving the resiliency of its customers and communities in the face of the increasing risk of PSPS events and wildfires. These efforts include behind-the-meter initiatives and programs to enhance resiliency at individual customer sites, as well as investigating opportunities to develop community microgrid solutions. For example, MCE has allocated $3 million in this fiscal year alone to support resiliency initiatives at facilities that provide critical community services during PSPS events. Under this initiative, MCE has been actively engaging with its local government and Office of Emergency Services ("OES") partners to identify the facilities that were critical in maintaining community support during the 2019 PSPS events. To date, MCE has identified more than 60 critical facilities across its service area that are prime candidates for SGIP incentives. Additionally, MCE published a request for proposals ("RFP") to identify qualified organizations to support MCE in the development of energy storage resiliency programs for residential customers.[8] The focus of the

[7] This number only includes customers who are currently on PG&E's Medical Baseline rate in MCE's service area. MCE currently does not have data on customers who have reported a medical need to the utility or those who have not been accounted to date. As described further below in the document, MCE is beginning outreach to customers with medical needs to be able to better account for this important vulnerable customer group and is working with PG&E on receiving additional customer data.

[8] MCE's RFP for behind the meter energy storage solutions can be found here.

RFP is to provide resiliency solution for MCE's most vulnerable customers, including, but not limited to, low-income customers, customers located in disadvantaged communities, and customers with medical needs.

For these reasons, MCE is uniquely positioned to partner with PG&E on the SGIP Equity ME&O Plan, and lead the community outreach efforts in MCE's service area. The Commission should *require* (not only encourage) the SGIP PAs to work with MCE and other CCAs in the development of a comprehensive SGIP Equity ME&O Plan by February 18, 2020.

B. CCAs should be given the opportunity to become the local community outreach partner under the SGIP Equity ME&O Plan in their service area

Given CCAs' local knowledge, community connections, close working relationships with local governments, and demonstrated willingness to dedicate significant funds to resiliency initiatives, the Commission should give CCAs the opportunity to become the local community outreach partner under the SGIP Equity ME&O Plan in their service area. CCAs interested in becoming SGIP Equity ME&O partners should be given the opportunity to submit community outreach plans to the Energy Division. If the Energy Division concludes that the CCA's plan is consistent with SGIP program goals and requirements, it should approve the plan, and direct the SGIP PAs to work with the respective CCA on SGIP Equity community outreach in the CCA's service area.

C. The Commission should approve *MCE's Community Outreach Plan for the SGIP Equity and Equity Resiliency Budget for Residential Customers* as a component of the SGIP Equity ME&O Plan through the disposition of the SGIP PAs' Advice Letter from December 17, 2019

The Commission established in D.19-09-027 that the SGIP PAs "take <u>specific steps to rapidly reach equity budget customers with critical resiliency needs</u> [emphasis added] to ensure that such customers receive the information they need to utilize SGIP incentives and to <u>appropriately and strategically collaborate with local governments and others</u> [emphasis added] to prioritize outreach efforts."[9]

[9] D.19-09-027 at p.57

While MCE supports the high-level, mass-market ME&O plan proposed by the SGIP PAs as a statewide approach for educating customers about the SGIP program, this plan alone will not lead to the desired results. The plan neither describes "specific steps to rapidly reach equity budget customers with critical resiliency needs" nor defines any "collaboration with local governments and others."

The SGIP PAs' proposal to work collaboratively with stakeholders in January 2020 to develop a comprehensive SGIP Equity ME&O plan through workshops is a positive initial step.[10] However, MCE cautions against the limited effectiveness of developing effective and implementable solutions for a joint comprehensive Equity ME&O Plan in just one workshop and under a very short timeline (the comprehensive ME&O plan is due February 18, 2020). Additionally, urgent action is needed to reach the most vulnerable *residential* customers with resiliency needs now, especially considering that the Commission determined that SGIP applications for residential resiliency customers must open on March 1, 2020 at the latest.

To accelerate coordination efforts and complement the residential Equity ME&O Plan submitted by SGIP PAs, MCE is submitting attached a "Community Outreach Plan for the SGIP Equity and Equity Resiliency Budget for Residential Customers" ("MCE Community Outreach Plan"). The plan outlines specific outreach strategies and tactics that could be implemented immediately to support and accelerate vulnerable customers' access to SGIP equity incentives. While the plan describes community outreach strategies to all eligible customers under the equity budget, MCE focuses its outreach on those vulnerable customers with the greatest resiliency needs.

With the proactive submission of the detailed MCE Community Outreach Plan, MCE demonstrates its ability and commitment to increasing the resiliency of the most vulnerable residential customers *now*. Hence, the Commission should not delay coordination between local government outreach partners and the SGIP PAs until the coordination for the comprehensive ME&O Plan occurs. Instead, the Commission should approve MCE's Community Outreach Plan for residential customers as a component of the SGIP Equity ME&O Plan through the disposition of the SGIP PAs' Advice Letter from December 17, 2019. This would allow MCE to begin customer outreach and recruitment immediately upon approval, gaining valuable time in

[10] *Joint Request by Self-Generation Incentive Program (SGIP) Program Administrators (PAs) in accordance with CPUC Rule of Practice and Procedure 16.6 for an Extension of Time to Submit Some of the Requirements pursuant to Ordering Paragraph 7 of Decision (D.)19-09-027,* from December 5, 2019 at p.3

implementing on-the-ground outreach efforts, considering that the next fire season is only months away.

D. The Commission must make the appropriate funding available for community outreach partners under the Equity ME&O Plan.

To be able to quickly, effectively and efficiently implement the community outreach strategies under the Equity ME&O plan, community outreach partners must have access to funding under the SGIP equity budget. In D.18-12-015, the Commission approved the concept of "Community Energy Navigators" for the San Joaquin Valley Disadvantaged Communities Pilot Projects and made funding available for those efforts.[11] MCE proposes that the Commission authorize a similar concept and funding strategy for community outreach partner under SGIP Equity ME&O Plan.

While the amount of funding and funding processes can be determined collaboratively with PG&E and other stakeholders, MCE recommends that the Commission must specifically direct the SGIP PAs to create a budget line item for community outreach partners, such as CCAs, under the new SGIP Equity ME&O budget.

III. CONCLUSION

MCE appreciates the Commission's consideration of the recommendations proposed above in regards to the SGIP PAs' Advice Letter filing on December 17, 2019.

Respectfully submitted,

/s/ *Jana Kopyciok-Lande*

Jana Kopyciok-Lande
Senior Policy Analyst
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
E-mail: JKopyciok-Lande@mcecleanenergy.org

[11] D.18-12-015, *Decision Approving San Joaquin Valley Disadvantaged Communities Pilot Projects*, at p.80ff

cc: Erik Jacobson, PG&E (PGETariffs@pge.com)
Gary A. Stern, SCE (AdviceTariffManager@sce.com)
Laura Genao c/o Karyn Gansecki, SCE (Karyn.Gansecki@sce.com)
Ray Ortiz, SoCalGas (rortiz@socalgas.com)
Sephra A. Ninow, CSE (sephra.ninow@energycenter.org)
Service list R.12-11-005

Appendix A

Community Outreach Plan for the Self-Generation Incentive Program's Equity and Equity Resiliency Budget for Residential Customers

Proposed by Marin Clean Energy

Jana Kopyciok-Lande
Senior Policy Analyst
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
E-mail: JKopyciok-Lande@mcecleanenergy.org

January 6, 2020

Table of Contents

Table of Figures

A. Objectives & Approach

MCE fully supports the objectives of the Self-Generation Incentive Program's (SGIP) Equity and Equity Resiliency Budget and is uniquely positioned to rapidly advance the program. As a Community Choice Aggregator (CCA) with a locally-elected board of directors and significant community outreach, MCE is very well connected to our communities and committed to helping vulnerable customers gain access to cleaner and more resilient energy options. MCE serves a significant population of approximately 83,000 low-income and medically-impacted[1] customer accounts, and approximately 40,000 customers located in disadvantaged communities (DACs). When considering customers who were directly impacted by Public Safety Power Shutoff (PSPS) events to date, vulnerable customers represent more than 50% of MCE's customer base of 470,000 customers.

As a community-based and customer-focused public agency, MCE has a close connection with our communities and a good understanding of how to reach vulnerable customer segments. Since its inception in 2010, MCE has established relationships with local community-based organizations (CBOs) and local government agencies that support these communities. CBOs are an active channel of communication from MCE to our communities, as well as bringing the voice of the community into MCE. Additionally, MCE has developed and successfully implemented a number of programs targeted at vulnerable communities, including programs for solar, electric vehicles, and energy efficiency. For these reasons, MCE is uniquely positioned to partner with PG&E on the SGIP Equity Marketing Education and Outreach (ME&O) plan, and lead the community outreach efforts for the SGIP Equity and SGIP Equity Resiliency Budget in our service area.

An enhanced and accelerated outreach effort is crucial in making the new SGIP Equity Resiliency Budget a success and increasing the resiliency of the most vulnerable customer segments before the next fire season. Since the SGIP Equity Budget was established in 2017, there has been very limited uptake in the equity portion of the SGIP program despite incentives of up to $0.50/Wh. While the Commission recently approved significant increases in the incentive levels for the SGIP Equity Budget and established the Equity Resiliency Budget with even higher incentive levels,[2] there remain significant challenges in identifying, reaching and enrolling eligible customers. For instance, developers often cite higher customer acquisition costs for low-income customers,

[1] This number only includes customers who are currently on PG&E's Medical Baseline rate in MCE's service area. MCE currently does not have data on customers who have reported a medical need to the utility or those who have not been accounted to date. As described further below in the document, MCE is beginning outreach to customers with medical needs to be able to better account for this important vulnerable customer group and is working with PG&E on receiving additional customer data.

[2] See D.19-09-027, *Decision Establishing a Self-Generation Incentive Program Equity Resiliency Budget, Modifying Existing Equity Budget Incentives, Approving Carry-Over of Accumulated Unspent Funds, and Approving $10 Million to Support the San Joaquin Valley Disadvantaged Communities Pilot Projects*, from 9/18/2019 and Proposed Decision, *Self-Generation Incentive Program Revisions Pursuant to Senate Bill 700 and Other Program Changes*, from 12/11/2019

customers living in DACs, and customers with medical needs. Among the reasons cited by developers are a high percentage of rental properties for this population and an older housing stock that may require new and/or upgraded roofing and/or electrical supply. Furthermore, identifying customers and ensuring that they meet eligibility criteria can often be challenging and requires significantly more time and effort. For instance, the Equity Budget requires residents of single-family homes to live in homes with resale restrictions, and multi-family residents to live in deed-restricted properties in order to qualify. Both of these low-income designations are not easy to identify due to the lack of public databases. Even more challenging to identify are customers who live in high-fire threat districts (HFTDs) and/or have experienced more than two discreet public safety power shutoff (PSPS) events.

In the sections below, MCE outlines specific recommendations on how MCE could complement and augment the residential ME&O plan submitted by the SGIP Program Administrators (PAs)[3] with tangible community outreach strategies that could be implemented immediately to increase the resiliency of our customers and communities before the next fire season.[4]

B. Background & Value Proposition

Community Engagement

MCE was founded on the principles of community choice and participation. Community partnerships, engagement and outreach are key elements of our energy services and program delivery model and integral to our success. MCE serves approximately 470,000 electricity accounts representing more than 1 million residents and businesses across Marin, Napa, Solano and Contra Costa counties. MCE engages customers through a mixture of direct outreach (advertisements, targeted mailings, emails, workshops, events, phone and in person contact) and indirect outreach efforts (social media, word-of-mouth, sponsorships, and referrals). Each year, MCE attends and supports hundreds of community events and directly engages with local

---

[3] Pacific Gas and Electric Company Advice Letter 4191-G/5714-E, Southern California Edison Company Advice Letter 4127-E, Southern California Gas Company Advice Letter 5555-G, and Center for Sustainable Energy Advice Letter 106-E, *Proposed Revision to the Self-Generation Incentive Program Handbook to Incorporate a New Equity Resiliency Budget for Residential Customers (Systems < 10kW) Including Changes to Incentive Structures, Program Requirements, Marketing Education and Outreach Plan, and Budget Allocations Pursuant to Decision 19-09-027,* from 12/17/2019

4 MCE and PG&E have initiated conversations about a potential collaboration under the SGIP Equity ME&O under which MCE would lead the community outreach efforts in its service area. MCE is looking forward to continuing this conversation and further developing a comprehensive ME&O plan, including outreach to non-residential customers, with PG&E and other stakeholders in early 2020 through workshops.

government partners and CBOs across MCE's service area to educate and expand access to clean energy programs.

Through its core work, MCE is already effectively engaging with tens of thousands of customers and partners relevant to the SGIP equity budget. MCE would be able to quickly ramp up to support SGIP equity ME&O efforts through its existing outreach channels: community and energy equity CBOs, local community centers, libraries, local public agencies including town and city offices, local fire departments, offices of emergency services (OES), schools, and other public health and emergency service partners. MCE will also build on its existing connections with local housing authorities to reach single-family and multi-family residents in affordable housing properties.

MCE takes its connection to the community in earnest and was the first CCA to form a community advisory committee, the "Community Power Coalition" (CPC).[5] The CPC holds bimonthly meetings and provides an avenue for customer and community engagement within MCE's service area. It specifically focuses on outreach to historically marginalized constituencies within MCE's many diverse and dynamic communities. The CPC is a collective powerhouse of more than 35 local organizations advocating for conservation, sustainable development, environmental justice, and disadvantaged communities.

Environmental Equity

MCE already proudly serves our income-qualified and disadvantaged communities with a wide range of energy efficiency, renewable energy and clean transportation offerings. MCE offers an electric vehicle rebate program that provides rebates for new electric vehicle purchases for low income individuals. In the energy efficiency realm, MCE runs the Low-Income Families and Tenants (LIFT) program under the umbrella of California's Energy Savings Assistance (ESA) program which provides no-cost home assessments, technical assistance, rebates and direct installation of energy saving measures for affordable multifamily properties. To date, MCE has worked with 24 properties representing 1,482 units in the LIFT program. Under this program, MCE also leverages other programs geared at energy, health, and safety improvements such as MCE's Multifamily Energy Savings Program and the Green & Healthy Homes Initiative (GHHI) Marin which combines energy efficiency upgrades with other health, safety and comfort measures. Finally, MCE complements solar rebates for low-income homeowners and affordable multifamily properties offered by the state with additional rebates. To date, over 250 income qualified homeowners and 2 affordable housing multifamily properties have installed solar through MCE's low-income solar program.[6]

Furthermore, MCE has spearheaded robust efforts with respect to supplier and workforce diversity. MCE has funded local training programs to create green career pathways in disadvantaged communities, has required local hire for solar development in our vulnerable communities, has

---

[5] The full list of ComPow members can be found at https://www.mcecleanenergy.org/community-power-coalition/

[6] In addition to the income qualified programs mentioned here, MCE is also the administering general market energy efficiency (EE) programs for all customer segments under the EE Rolling Portfolio.

been a featured presenter for multiple years at the Commission's Supplier Diversity En Banc, and hosted a "Certify and Amplify" event to encourage local, diverse businesses to become G.O. 156-certified.

Supporting Vulnerable Customers during PSPS Events

MCE is extremely concerned about the effects of multiple and extended PSPS events in 2019 and the potential for an increased number of such events in the future. More than 50% of MCE accounts are considered "vulnerable" and potentially eligible for the SGIP equity budget because they are low-income customers, customers with a medical need, located in a DAC or a HFTD, or have been impacted by PSPS events to date. MCE provides more data on vulnerable customers in its service area in the section on target customers below.

MCE has been proactively distributing messages through its social media platforms, e-newsletter, and website, encouraging customers to review PG&E's "Steps to Prepare" and sign up for wildfire safety shutoff alerts. In addition, MCE has initiated several collaborative efforts with local government and CBO partners to increase the resiliency of our communities before the next fire season. In June 2019, MCE took the initiative to partner with OES and public health partners to proactively email medical baseline customers to encourage them to sign up for PSPS alerts. During MCE's September 2019 Board Retreat, attended by member community Board members, MCE staff, Community Power Coalition members and members of the public, key leaders from Napa and Contra Costa County's Risk & Emergency Services Departments presented key areas of collaboration and future needs to better prepare residents and businesses in emergencies and PSPS events. Furthermore, MCE's supported our local member governments in applying for grants through the CalOES' "2019-20 Public Safety Power Shutoff (PSPS) Resiliency Allocation to Cities" request for proposal (RFP).[7] MCE staff established an outreach initiative to each of the incorporated cities within its service area to help support each city's grant application by providing a response template, offering PSPS event data, and extending support to help each eligible city meet the state's application deadline. As a result of these efforts, MCE deepened its relationships with city staff most closely tied to facility-specific resiliency efforts and collected comprehensive lists of the cities' most vulnerable critical facilities. Most recently, MCE has been working directly with its four-county OES leads to identify and better prepare vulnerable communities for extended shutoffs.

By working with municipal and community partners to identify additional vulnerable customer populations and critical facilities in our service area, MCE is expanding the reach of future outreach campaigns and helps serve as a point of coordination for resiliency efforts in our service area.

[7] More information about the RFP can be found on the CalOES website here

MCE's Single Point of Contact (SPOC) Model

MCE offers a multitude of clean energy and energy efficiency programs to its customers. MCE prides itself in providing excellent customer service to program participants while also ensuring that customers can easily take advantage of all the clean energy programs, they may be eligible for. These "guiding principles" for program implementation are embedded in MCE's Single Point of Contact (SPOC) model, under which MCE provides real-world, day-to-day support to program participants to make participation in a clean energy programs as simple as possible.

Under the SGIP Community Outreach Plan, MCE will take advantage of its experience providing SPOC services to customers in MCE's service area and will support eligible customers with:

- Technical assistance in planning, vendor selection and completing applications for SGIP incentives;
- Coordination and incentive leveraging with existing low-income solar programs such as the Single Family Affordable Solar Housing (SASH) and DAC SASH, Solar on Multifamily Affordable Housing (SOMAH) and Multifamily Affordable Solar Housing (MASH) programs;
- Access to MCE's programs and services including energy efficiency, EV and low-income solar rebates;
- Leveraging additional funding opportunities from external partners such as the Marin Community Foundation, among others.

Since its inception, MCE has innovated on many fronts and looks forward to continuing to develop programs and address residential equity and resiliency market gaps that are targeted to the unique needs of our service area.

C. Prioritization of Target Customers

MCE's service area includes a significant number of disadvantaged and vulnerable customers. MCE serves approximately 12,500 medical baseline customer accounts, 69,500 CARE accounts, and 1,600 FERA accounts. Approximately 40,000 of MCE's service accounts are located in DACs. During the 2019 PSPS events, 141 electrical circuits were impacted within MCE's service area and 162,000 MCE customer accounts are estimated to have been impacted. This translates to a community impact of approximately 500,000 individuals and approximately a third of MCE's customer accounts.

While MCE intends to reach out to all eligible customers under the SGIP Community Outreach Plan, we propose to prioritize certain residential customer segments in the initial outreach phases due to their immediate and urgent need for improved resiliency during PSPS events. MCE describes each of these prioritized target customers segments in the following.

Customers with Medical Needs

MCE has run analyses to identify the number of customers with medical needs located within its service area. At this point in time, MCE is only able to identify customers on PG&E's medical baseline rate. Unfortunately, MCE does not have access to data on those customers who have notified PG&E of a serious illness or condition that could become life-threatening if electricity is disconnected. MCE is actively working with PG&E to get access to additional customer data and hopes to be able to further identify those customers with medical needs in Q1 2020. For the time being, MCE has identified the following numbers of eligible medical baseline customers in MCE's service area:

- **Medical Baseline Customers Located in Tier 2 or 3 HFTDs:** MCE has conducted a spatial analysis and found that at least 607 medical baseline customers are located within Tier 2 and 3 HFTD in MCE's service area.[8]

- **Medical Baseline Customers Who Have Experienced Two or More Discrete PSPS Events:[9]** MCE is able to determine which customer accounts have been impacted by previous PSPS events through electrical feeder data. MCE overlaid this information with customer accounts enrolled in the medical baseline rate and found that 3,533 active medical baseline accounts were impacted by two or more PSPS events in 2019 within MCE's service area.[10] This amounts to 29% of all medical baseline customers in MCE's service area. The table below identifies affected customers by County.

Table 1: Medical Baseline customers who have experienced two or more 2019 PSPS events

Number of active medical baseline accounts that have experienced more than two 2019 PSPS events							
Location	**Two times**	**Three times**	**Four times**	**Five times**	**Six times**	**Seven times**	**Total medical baseline accounts impacted by two or more PSPS events**
Marin County	1,034	394					1,428
Contra Costa County	879	545					1,424
Napa County		130	82	77	334	58	681
Total Account Count	**1,913**	**1,069**	**82**	**77**	**334**	**58**	**3,533**

[8] These numbers are estimates as MCE currently does not have access to the appropriate geographic attributes (i.e., latitude/longitude) to clearly identify and map customers. MCE is expecting to receive lat/long information for MCE customers from PG&E in Q1 2020 and will then be able to run a more accurate analysis of eligible customers. For now, it should be noted that the number of eligible customers could rise by as much as 25%.
[9] Prior to the date of application for SGIP incentives.
[10] This number includes customers that have opted out of receiving MCE generation service.

Customers Participating in Income Qualified Programs

A second target customer segment MCE will focus on are customers who have previously participated or are currently enrolled under other solar programs targeting vulnerable customers. More specifically, these programs include the SASH, DAC SASH, MASH and SOMAH programs. MCE has identified the following program participation numbers in its service area and is looking forward to engaging these customers under the SGIP Equity and Equity Resiliency programs.

- **Customers participating in SASH or DAC-SASH programs**: Over the last 11 years, 539 customers located in MCE's service area have participated in the SASH program. More detail on the participating customers by city and county can be found in the table below. The DAC-SASH program is still under development and no customers have participated to date.

Table 2: Number of Completed SASH Applications in MCE's Service Area

	Completed Applications	Total CEC PTC Rating (KW)
Contra Costa	**514**	**1,285**
Antioch	17	52
Bay Point	19	55
Concord	8	23
Crockett	2	3
El Sobrante	2	7
Hercules	1	2
Martinez	19	51
Oakley	7	18
Pinole	1	2
Pittsburg	79	247
Richmond	340	778
Richmond, ca	1	2
Rodeo	4	11
San Pablo	6	14
Walnut Creek	8	20
Marin	**17**	**38**
Larkspur	2	5
Marin City	1	1
Martinez*	2	5
Novato	11	25
Saulsalito	1	2
Napa	**4**	**12**
Napa	3	11
Yountville	1	1
Solano	**4**	**7**
Benicia	4	7
Grand Total	**539**	**1,343**

** Data displayed is using the data fields and values provided from the original dataset indicated above. Data issues and errors were not fixed or addressed. (E.g. SASH dataset states that "Martinez" is part of Marin County.)*

- **Customers participating in MASH program:** To date, 54 multi-family properties located in MCE's service area have participated in the MASH program with 53 of these properties having completed the solar installation. More detail on the participating customers by city and county can be found in the table below.

Table 3: MASH Application Status and Number of Applications in MCE's Service Area

	Reservation Reserved	Completed	Application Total
Contra Costa	**1**	**31**	**32**
Antioch		2	2
Brentwood			0
Clayton		1	1
Concord		2	2
Danville		1	1
El Cerrito	1		1
Hercules		2	2
Martinez		1	1
Oakley		2	2
Pacheco		1	1
Pinole		2	2
Pittsburg		1	1
Pleasant Hill		2	2
Richmond		8	8
Rodeo		1	1
San Pablo		3	3
San Ramon			0
Walnut Creek		2	2
Marin		**18**	**18**
Belvedere Tiburon		1	1
Corte Madera		1	1
Fairfax		1	1
Larkspur			0
Mill Valley		2	2
Novato		8	8
Point Reyes Station		1	1
San Rafael		4	4
Tiburon			0
Napa		**4**	**4**
American Canyon			0
Napa		2	2
Saint Helena		1	1
Vallejo		1	1
Grand Total	**1**	**53**	**54**

- **Customers participating in the SOMAH program:** The SOMAH program is a relatively new program that has only recently begun accepting incentive reservations. Based on the data obtained, MCE believes there are at least 17 active applications for this program within its service area. The table below shows the number of incentive applications by status and county.

Table 4: SOMAH Application Status and Number of Applications in MCE's Service Area

	Pending IOU Data	Reservation Request Review	Resubmitted Reservation Request	Waitlist	Grand Total
Contra Costa	2	2	1	3	8
Marin				1	1
Napa	1				1
Solano	1	2		4	7
Grand Total	**4**	**4**	**1**	**8**	**17**

In addition to reaching out to participating customers under these income-qualified solar programs, MCE will also leverage its experience running the LIFT pilot program, which provides energy efficiency upgrades to income qualified multifamily properties. MCE will apply the SGIP eligibility screen to multifamily properties who have participated in the LIFT program and with whom MCE has existing relationships to identify eligible customers for the SGIP equity budget.

In summary, MCE has initially identified approximately 4,700 single-family and multi-family residential customer accounts in our service area for a focused and prioritized outreach effort that could begin immediately. MCE expects that number to increase substantially following a more detailed future analysis, pending additional data supplied by PG&E.

Additionally, MCE will continue its engagement and coordination with local government and community partners to identify vulnerable customers that may be missed when applying the more data-driven approach described above. MCE has learned from recent outreach to medical baseline customers that there is a need to further identify customers with medical equipment that are neither on a medical baseline rate, nor have registered with the utility as having a medical need. Those customers are especially vulnerable to future PSPS events and targeted outreach must be undertaken with local health departments to identify those customers and provide the support they need. MCE is already working on such an initiative as described in more detail below.

Finally, MCE has already identified 60+ critical facilities and disadvantaged community support organizations across its service area including evacuation centers, key community and senior resource centers, critical and emergency services, and locations serving vulnerable populations. This working list is being informed by county and city partners, along with key community stakeholders. These efforts are integral in informing outreach to critical facilities in our service area and MCE is looking forward to working with PG&E and other stakeholders on developing a ME&O plan for non-residential customers in early 2020

D. ME&O Strategy

General Education and Outreach Campaign

MCE's approach to marketing, education and outreach to support the objectives of the SGIP Equity and Equity Resiliency Budget will leverage PG&E's equity resiliency marketing in addition to existing MCE direct and indirect customer and partner engagement channels. Opportunities to partner with PG&E will include:

- MCE to co-brand and help disseminate any PG&E collateral;
- MCE will promote/share social media messaging on its own platforms;
- MCE and PG&E joint development of targeted customer list/data sharing;
- MCE can lead on co-branding of customer outreach material within MCE service area, including opportunities for local agencies and CBOs to participate in co-branding; and
- MCE to identify community ambassadors and energy navigators to increase reach and effectiveness.

The approach described below allows for MCE and PG&E to partner efficiently and cost effectively on SGIP ME&O efforts and have the benefit of existing, proven MCE community outreach expertise to appropriately target customer populations. MCE will incorporate PG&E's SGIP marketing material into existing community and customer outreach efforts and leverage high impact digital engagement channels, co-branded engagement with cities and partner organizations, and in-person outreach and education.

MCE's goal is to support a "high-level and high impact" outreach campaign that can be easily customized for co-branded and targeted outreach efforts with local government and community partners. This leveraged approach is cost effective, proven and follows similar successful models such as the San Joaquin Valley Community Energy Navigator program and MCE's Community Power Coalition.

Content & Messaging

To avoid duplication of efforts, MCE will mostly leverage marketing material developed by the SGIP PAs/ PG&E for community outreach efforts. Materials should be either co-branded or neutrally branded. Additionally, MCE should have the opportunity to provide content and branding edits to develop highly targeted outreach material as needed for outreach to the most vulnerable customers groups. Those customer groups will likely respond favorably to more localized or individualized messaging (e.g., medically impacted customers).

Customer-facing messaging will be simple and focused on "resiliency" to get participants into the door, followed by an offer of all program options and other available resources (co-funding or other support). A variety of support options and clear next steps, including options for technical assistance, will also be provided in materials.

MCE will ensure that education and outreach content follows best practices outlined in the CA Alert and Warning Guidelines. MCE will also utilize key PSPS resources (such as the "Prepare for Power Down" statewide campaign) to develop content describing the availability of equity resiliency incentives.

Partner Content & Toolkits

MCE will leverage any potential toolkits being developed by the SGIP PAs and augment them with localized and targeted materials for the prioritized customer groups as described earlier in this document. This 'MCE Resiliency Toolkit' will not only include information about the SGIP (Equity) program, but also about other programs offered to vulnerable customers with resiliency needs, as well as fund leveraging opportunities such as the GHHI program or other local resiliency grants and programs. MCE is aware that customers can easily get overwhelmed by a multitude of programs and marketing materials related to such programs and will hence target the SGIP Resiliency Toolkit mostly at partner organizations who will then work with customers one-on-one to discuss options for program participation on an individualized level.

The MCE Resiliency Toolkit will be easily accessible online or via printed packets. The toolkit will include shareable social media, digital content and collateral that can be easily adapted. MCE will also track toolkit downloads and create digital intake forms for resiliency partner sign up to track outreach effectiveness.

Targeted Outreach Activities

MCE will email the MCE Resiliency Toolkit to approximately 200 CBOs, equity and local government partners. This email will also include a link to the online toolkit available for download on the MCE website, as well as information about how to collect the hardcopy version of the toolkit from MCE. The initial outreach email will also include an invitation to a residential resiliency kick-off webinar to introduce the outreach campaign to community partners.

In addition to this MCE-led email campaign, MCE will also offer to develop targeted and co-branded email outreach campaigns in collaboration with public agency partners (e.g., OES, public health agencies and/or local governments).

MCE will initially target the following local government and community partners (lists are not exclusive, organizations listed are examples of MCE's ongoing partnerships):

- **Local government and public agency partners (100+)**
  - Contra Costa Department of Conservation and Development
  - Contra Costa Health Services
  - Marin Housing Authority

- Marin County Health and Human Services
    - Napa Valley County Health and Human Services Association
    - Bolinas Community Public Utility District
- **City and County OES partners**
    - Marin County Fire Department
    - Contra Costa County Fire Protection District
    - Bolinas Fire Protection District
    - San Ramon Valley Citizen Corps Council
- **MCE Community Power Coalition (CPC):** 35 organizations, including but not limited to:
    - Asian Pacific Environmental Network
    - Communities for a Better Environment
    - The Greenlining Institute
    - Richmond Build
    - Sierra Club, Bay Area Chapter
    - 350 Bay Area
    - Sustainable Rossmoor
    - Marin Conservation League
    - Sustainable Napa County
- **Local CBO and advocacy partners,** in addition to MCE Community Power Coalition:
    - Marin Community Foundation
    - The Climate Center
    - Canal Alliance
    - Napa Valley Grape Growers Association
    - Napa Valley Vinters
    - Solano Resource Conservation District
    - Solano County Farm Bureau
- **Organizations serving vulnerable populations:**
    - Central Coast Energy Services
    - Marin Center for Independent Living
    - Community Action Marin
    - Marin County Aging Action Initiative
    - Whistlestop
    - West Marin Senior Services
    - George and Cynthia Miller Wellness Center
    - Margaret Todd Senior Center
    - Coastal Health Alliance
    - Petaluma Health Center Community Clinic
- **Chambers of Commerce:** Over 34 diverse local Chambers of Commerce memberships, including:
    - Solano Hispanic Chamber
    - Solano County Black Chamber

- Hispanic Chamber of Contra Costa County
    - Napa City Hispanic Chamber
    - El Cerrito Chamber
    - El Sobrante Chamber
- **MCE Board and Committee members**

Webinars, Community Workshops and Events

In MCE's experience, the most impactful channels to reach vulnerable customers are in-person and on-the-ground community outreach and engagement. Many vulnerable customers have limited access to computers or online access but instead rely to a large extent on in-person interaction and printed materials. Additionally, messaging and outreach is most effective when implemented by trusted messengers on a local level who are familiar with the local challenges and impacts of PSPS events and other resiliency challenges.

For those reasons, MCE will focus its community outreach efforts on in-person, on-the-ground engagement activities. MCE staff is already present at hundreds of community events such as farmers markets, local festivals, and fairs and will seamlessly incorporate the SGIP message into its offerings.

Additionally, MCE will educate local partner organizations about the SGIP program in general, and the resiliency incentives in particular, to help spread the word efficiently and effectively throughout its communities. MCE will offer a "Residential Resiliency Kick-off Webinar" to introduce the outreach campaign to community partners. MCE will also provide community partners with direct contact information for MCE staff for any follow-up questions. Furthermore, MCE will hold community workshops and/or attend community events, such as Town Council meetings, to spread the word about the SGIP equity resiliency incentives. Finally, door-to-door canvassing may be implemented by community partners in areas where the most vulnerable customer populations are located.

Direct to Residents (Website and Social Media)

MCE will develop targeted email lists that can be used for direct MCE outreach or partner campaigns. Target customers will receive resiliency information through a variety of existing channels including website content, e-news, and social media. The initial expected monthly reach is 40,000-50,000 customers.

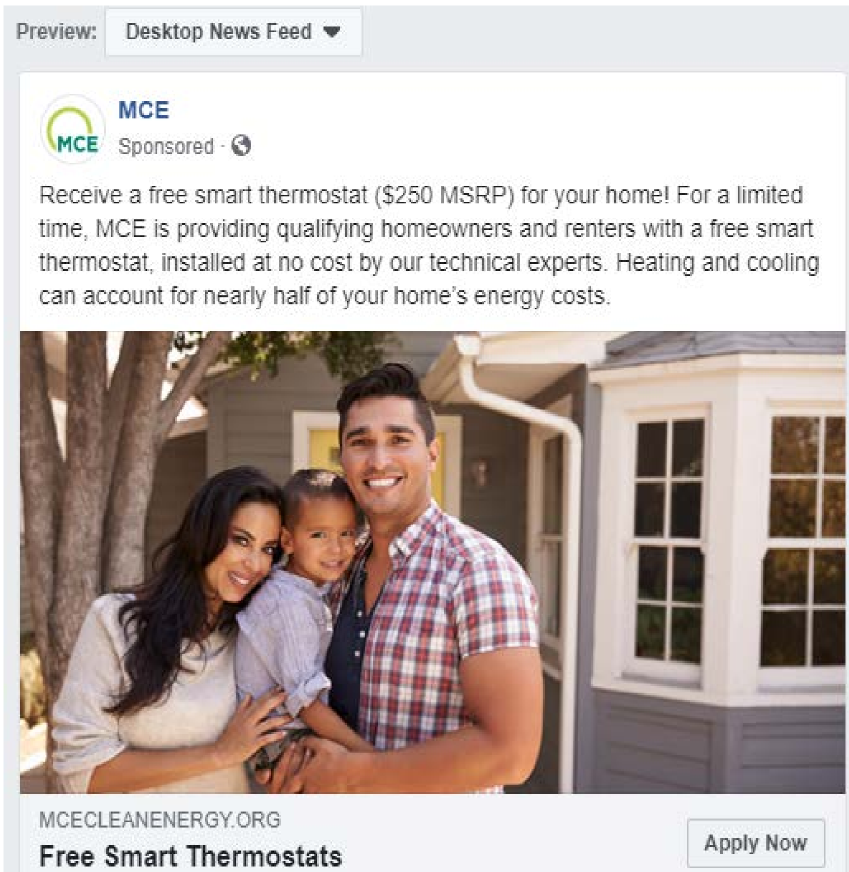
Stakeholder Outreach and Coordination

MCE will further refine its outreach strategies by continuously engaging with stakeholders and partners and requesting feedback on the effectiveness of the outreach campaigns. One such partner organization that MCE will seek feedback from is the DAC Advisory Group. Once granted approval of its community outreach plan, MCE will present its SGIP Community Outreach Plan and related resiliency initiatives to the DAC Advisory Group. MCE will request feedback from the group if there are any unmet needs that MCE isn't addressing, if there are any additional best practices for reaching our target communities, and if there are additional local community organization that we should connect with under the outreach plan.

MCE Customer Outreach Examples

Below are some relevant examples of MCE's targeted co-branded outreach campaigns to date.

Social Media - Targeted Engagement for Smart Thermostats Customers



Co-Branded Emails for Income-Qualified EV Rebates

HelloHello

The City of Pinole and MCE are proud to announce that you may be eligible to save $3,500 on the purchase or lease of an electric vehicle (EV).

MCE's generous **rebate for low-income qualifying customers** gives you a great deal on a cutting-edge, new or used EV, especially when you combine it with up to $8,800 in other incentives from the federal government, State of California, and PG&E.

EVs are zero-emission vehicles that offer significant savings on fuel and maintenance costs, and also reduce air pollution in your community.

Click to Learn More About MCE's EV Rebate Program

Sincerely,
City of Pinole and MCE

Co-Branded Email Outreach for Medical Baseline Customers

Good afternoon ,

With the start of this year's fire season, we wanted to encourage our customers and community members to prepare for PG&E's Public Safety Power Shutoff (PSPS) events. These events are part of PG&E's Community Wildfire Safety Program. Based on PG&E's information, shutoffs could potentially last more than 48 hours, resulting in concerns for high risk customers such as those enrolled in the Medical Baseline Program. The first PSPS event took place earlier this month affecting customers in MCE service area including parts of Napa and Solano Counties.

Please note that neither Solano County nor MCE have control over when these power shutoffs occur or how long they may last. MCE is not directly involved in transmitting and distributing electricity nor evaluating if weather conditions meet the criteria for planned power shutoffs. That is PG&E's responsibility.

As your local electric generation service provider, we want to provide you with resources to prepare for any potential shutoff events.

The first thing all customers should do is **sign-up** here for PSPS alerts from PG&E. Signing up for alerts allows you to receive direct and real-time communications from PG&E prior to and during power shutoffs.

Additionally, Solano County's Office of Emergency Services has prepared a quick guide for residents on how to prepare for power shutoffs. The guide is linked here providing an overview of PSPS events and tips for what to do before a power shutoff. The guide also includes special considerations for residents who use electricity and battery-dependent assistive technology and medical devices. Follow this link for tips on how to create a family emergency preparedness plan. You can also register for alerts through the County's Alert Solano emergency notification system.

If you have any further questions, you can reach out to:

- **PG&E**, 1-800-743-5002, or www.pge.com/wildfiresafety
- **Solano County's Office of Emergency Services**, 1-707-784-1600
- **MCE**, 1-888-632-3674 or email to info@mcecleanenergy.org

We understand that these upcoming shutoffs can be disruptive and even life-threatening. We encourage all of our customers to take the necessary precautions to prepare for such an event.

Thank you,
MCE and Solano County

Targeted Outreach Campaign and Technical Assistance for the Most Vulnerable Customers

In addition to the general marketing and outreach campaign directed at all eligible equity and equity resiliency customers in MCE's service area, MCE will also implement a targeted outreach and technical assistance campaign for MCE's most vulnerable customers and critical facilities.[11] This targeted outreach campaign will be a focused, localized and highly specialized ME&O effort, to not only identify and connect the most vulnerable customers with the SGIP Equity/ Equity Resiliency program but also to provide a full suite of support measures, including technical assessments and program leveraging support, to enable program participation. MCE is proposing the following targeted outreach channels and tactics for our prioritized target customers as described in Section C above:

Outreach to Customers with Medical Needs

As an outcome of the recent PSPS events, MCE recognized that many customers with medical needs are currently not enrolled in PG&E's medical baseline program. Therefore, MCE has been working on a joint outreach campaign in partnership with city and county OES personnel, key municipal staff, and local CBOs with the purpose of encouraging eligible customers with medical needs to enroll in PG&E's medical baseline program. The "2020 Medical Baseline Awareness Campaign" will include several key components: identifying eligible customers, identifying barriers to customers self-identifying as medical baseline (i.e. lack of knowledge, language barriers, trust barriers, misconception around eligibility such as only low income customers qualify, ect.), and challenges related to making contact with eligible customers by phone or email. Campaign outreach may include the creation of flyers which can be distributed by CBOs, local businesses, health agencies, and city/county e-Newsletters.

MCE will leverage the outreach implemented under the 2020 Medical Baseline Awareness Campaign to also introduce customers to storage and/or solar+storage opportunities under the SGIP Equity and Equity Resiliency program, as well as other clean energy and fund leveraging opportunities. Under the campaign, MCE will work with County Health Departments staff to educate front line workers on the importance of informing eligible individuals on the benefits of enrolling in the medical baseline program and coordinating SGIP application referrals where possible. In addition, MCE's co-branded SGIP program materials will be made available in local clinics and Health and Human Services offices, to highlight the availability of the SGIP program and technical assistance services. Additionally, MCE will seek match funding to cover any remaining costs of the storage and/or solar plus storage projects from partnering organizations for the most vulnerable customers.

[11] The targeted outreach campaign for critical facilities will be described in more detail in the comprehensive ME&O plan filing in February

Outreach to Customers Participating in Income Qualified Programs

California offers a plethora of clean energy, energy efficiency and storage programs for residential and non-residential customers, with several of them targeting income qualified customers or disadvantaged communities. However, clean energy program offerings are often siloed from one another, which creates a burdensome and confusing enrollment process for customers. MCE's SPOC model provides "behind-the-scene" coordination with various programs and funding resources in order to provide our customers with the comprehensive services they need. By creating partnerships with local service providers and leveraging different program offerings, MCE is able to reach new customers while streamlining program enrollment and breaking down the barriers to program participation. Additionally, program leveraging through the SPOC model enables customers to take advantage of all the programs available to them, thereby maximizing the benefit to the customers and improving the value of all leveraged programs.

Under the SGIP Community Outreach campaign, MCE is planning on coordinating closely with GRID Alternatives to jointly identify customers eligible for participation in both income qualified solar (SASH, DAC-SASH, SOMAH) and storage (SGIP Equity/ Equity Resiliency) programs.[12] MCE sees this customer subset as a prime target for outreach as combined solar plus storage systems can provide much greater resiliency benefits during prolonged outages than a storage system alone could offer.

For eligible customers who have not installed solar systems yet but are interested in doing so, MCE will seek match funding from other funding partners and/or MCE's self-funded resiliency funds to cover any remaining costs of the storage and/or solar plus storage project.

MCE will also leverage its experience running the LIFT pilot, an energy efficiency program for income qualified multifamily properties. MCE's LIFT program has provided assessments to 24 affordable properties representing 1,482 units over the last two years. MCE will identify eligible candidates among past program participants and will include information about SGIP in future program outreach efforts. Program outreach includes working with local governments to co-market the program and working through existing relationships with larger property management companies.

Finally, through MCE's local government outreach, MCE has identified communities and households solely reliant on electric pumps wells, such as the communities of Bolinas in Marin County. MCE stands ready to begin outreach to these customers before the next fire season.

[12] MCE and GRID Alternatives have already been in initial planning discussions. GRID Alternatives has confirmed that they are interested and available to move forward with the collaboration if additional SGIP ME&O funding is made available to pair with low-income solar ME&O resources.

Technical Assistance

MCE recognizes how challenging it is for customers to evaluate clean energy options available to them via the SGIP program, as well as navigating the application process. With funding support from the SGIP ME&O budget, MCE will provide technical assistance to ensure our vulnerable customer population, and the local agencies that provide support to these communities, have access to resources to help them acquire and install clean energy options via the SGIP Equity and Equity Resiliency programs. MCE's technical assistance will include the following elements:

1) Technology evaluation, selection and installation support;
2) Support in selecting a vendor; and
3) Support with the SGIP application process.

Once eligible customers are identified and screened for participation in either the Equity or Equity Resiliency programs, MCE will provide assistance in evaluating each customer's options for solar PV and energy storage, such as sizing, costs/benefits, energy efficiency improvements, and any possible building and/or electric upgrades necessary. To the extent there are other programs available to these customers for energy efficiency, structural or electrical upgrades, whether offered by MCE, PG&E or other agencies, MCE will assist customers with accessing these programs, incentives or funds. MCE may do this using a combination of in-house resources and tools, with support from our technical assistance contractor. Once the customer decides to install solar and/or energy storage, MCE or its contractor will guide the customer through the permitting, installation and interconnection process.

If needed, MCE will also help the customer select a licensed and qualified contractor, leveraging independent third-party analysis of contractors. MCE may maintain a list of trusted partners that have experience working specifically with low-income, DAC and medical needs customers to ensure the specific needs of these vulnerable communities are met.

Finally, MCE will help guide the customer through the SGIP application process, from the initial application to the final commissioning of the system. Working with the selected contractor, MCE will help customers understand and complete any required documentation and forms to facilitate a smooth application process to ensure the project is approved with minimal delays.

-

Appendix B

MARIN CONSERVATION LEAGUE

Protecting Marin Since 1934

January 3, 2020

President Batjer
Commissioner Rechtschaffen
Commissioner Guzman-Aceves
Commissioner Shiroma
Commissioner Randolph
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California

RE: MCE Proposed Self-Generation Incentive Program Equity Marketing, Education, and Outreach Plan

Dear President Batjer and Commissioners,

The Marin Conservation League supports MCE's Self-Generation Incentive Program (SGIP) Equity Marketing, Education & Outreach (ME&O) Plan.

The Marin Conservation League has been preserving, protecting, and enhancing the natural assets of Marin County for over eighty-five years, and presently includes in its areas of focus mitigating climate change, and thus, support for MCE and its mandate. We share with MCE a commitment to helping vulnerable community members gain access to cleaner and more resilient energy options. We believe that it's now more important than ever, in the aftermath of California's devastating wildfires, to expand access to solar-battery backup systems to those at greatest risk.

We believe that MCE with its four-county service area can accelerate SGIP participation and are willing and ready to collaborate with MCE on local community engagement activities.

MCE's proposed SGIP Equity ME&O Plan is just the kind of program we've been looking for. It outlines specific outreach strategies that could be implemented immediately to support and accelerate underserved communities' access to SGIP equity incentives, substantially increasing the adoption of battery storage, bringing economic and workforce opportunities to our most disadvantaged communities, and reducing the need to operate conventional gas-powered facilities in these communities with their accompanying air pollution and greenhouse gas emissions.

Marin Conservation league looks forward to working with MCE and other stakeholders to implement a strong SGIP Equity ME&O plan in 2020.

Sincerely,

Doug Wilson
Co-Chair, Climate Action Working Group

Bob Miller
Co-Chair, Climate Action Working Group

PHONE: 415.485.6257
FAX: 415.485.6259
EMAIL: mcl@marinconservationleague.org
WEB: marinconservationleague.org
ADDRESS: 175 N. Redwood Dr., Ste. 135
San Rafael, CA 94903-1977

COUNTY OF MARIN

DEPARTMENT OF
HEALTH AND HUMAN SERVICES
Promoting and protecting health, well-being, self-sufficiency, and safety of all in Marin County.

MARIN HEALTH & HUMAN SERVICES
Health, Well-being & Safety

Benita McLarin, FACHE
DIRECTOR

Matthew Willis, MD, MPH
PUBLIC HEALTH OFFICER

Lisa M. Santora, MD, MPH
DEPUTY PUBLIC HEALTH OFFICER

3240 Kerner Boulevard
San Rafael, CA 94901
415 473 4163 T
415 473 6002 F
415 473 3232 TTY
marinhhs.org/public-health

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

January 3, 2020

President Batjer
Commissioner Rechtschaffen
Commissioner Guzman Aceves
Commissioner Shiroma
Commissioner Randolph

Subject: MCE Proposed Self-Generation Incentive Program Equity Marketing, Education & Outreach Plan

Dear Commissioners,

Marin Health and Human Services (Marin HHS) is pleased to support MCE's Self-Generation Incentive Program (SGIP) Equity Marketing, Education & Outreach (ME&O) Plan. We value our partnership with MCE and their efforts to build a more resilient and healthier community by providing cleaner, sustainable energy options for our most vulnerable residents. Last year's devastating wildfires and power shutoffs reaffirmed the importance of investments in renewable energy sources as well as expanding equitable access to battery-solar backup systems to those at greatest risk, including those with access and functional needs (AFN).

We believe that MCE can rapidly accelerate SGIP participation within its 4-county service area and are excited about the possibility of collaborating on local community engagement activities. MCE's proposed SGIP Equity ME&O Plan outlines effective outreach strategies that could be implemented immediately to support and accelerate vulnerable customers' access to SGIP equity incentives. These incentives have the potential to 1) increase the adoption of battery storage, 2) bring positive economic and workforce development opportunities to disadvantaged communities, and 3) reduce the need to operate conventional gas facilities in these communities.

Marin HHS looks forward to collaborating with MCE and other stakeholders to implement a comprehensive SGIP Equity ME&O plan in 2020.

Sincerely,

Lisa M. Santora, MD, MPH

Our mission
Deliver speed and scale greenhouse gas reductions, starting in California.

Contact
www.theclimatecenter.org
P.O. Box 3785, Santa Rosa, CA 95402
707–525-1665

January 1, 2020

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

President Batjer
Commissioner Rechtschaffen
Commissioner Guzman Aceves
Commissioner Shiroma
Commissioner Randolph

Subject: Climate Center Support for MCE Proposed SGIP Marketing, Education & Outreach Plan

Dear Commissioners,

The Climate Center is pleased to support MCE's proposed SGIP Marketing, Education & Outreach (ME&O) Plan. Like MCE, the Climate Center is well attuned to local communities and is committed to helping vulnerable customers gain access to cleaner and more resilient energy. In the aftermath of so many devastating wildfires and power outages, it is more important than ever to expand equitable access to battery-solar backup systems to those at greatest risk.

We believe MCE can rapidly accelerate SGIP participation within its service area and are excited about the possibility of collaborating with MCE on local community engagement.

MCE's proposed SGIP ME&O Plan outlines specific tangible outreach strategies that could be implemented immediately to support and accelerate vulnerable customers' access to SGIP equity incentives, substantially increasing the adoption of battery storage, bringing positive economic and workforce development opportunities to some of California's most disadvantaged communities, and reducing the need to operate conventional gas facilities in these communities.

The Climate Center looks forward to collaborating with MCE and other stakeholders to implement a comprehensive SGIP Equity ME&O Plan in 2020.

With best regards,

Kurt Johnson
Advanced Community Energy Manager
The Climate Center

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill No. 1488 (2004 Cal. Stats., Ch. 690 (Sept. 22, 2004)) Relating to Confidentiality of Information.	Rulemaking 05-06-040 (Filed June 30, 2005)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION PETITION FOR MODIFICATION OF DECISION 06-06-066 AS AMENDED BY DECISIONS 07-05-032, 06-12-030, AND 08-04-023

Irene K. Moosen
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
415.587.7343
regulatory@cal-cca.org

Director, Regulatory Affairs
California Community Choice Association

Evelyn Kahl
Ann Springgate
Buchalter, A Professional Corporation
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
ekahl@buchalter.com

Counsel to the California Community Choice Association

January 21, 2020

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

Statutes

Senate and Assembly Bills

California Public Utilities Commission Decisions

California Public Utilities Commission Rules

Other Sources and Publications

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

Order Instituting Rulemaking to Implement Senate Bill No. 1488 (2004 Cal. Stats., Ch. 690 (Sept. 22, 2004)) Relating to Confidentiality of Information.	Rulemaking 05-06-040 (Filed June 30, 2005)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION PETITION FOR MODIFICATION OF DECISION 06-06-066 AS AMENDED BY DECISIONS 07-05-032, 06-12-030, AND 08-04-023

Pursuant to Rule 16.4 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the California Community Choice Association (CalCCA)[1] hereby submits this Petition for Modification of Decision (D.) D.06-06-066 as amended by D.07-05-032, D.06-12-030, and D.08-04-023. The Petition meets the requirements of Rule 16.4(d), as detailed in Section IV.

I. INTRODUCTION AND EXECUTIVE SUMMARY

Decision 06-06-066, which implemented Senate Bill (SB) 1488,[2] established detailed procedures to be followed when an investor-owned utility (IOU) seeks confidential treatment of "market sensitive" information submitted in procurement plans and related documents. In establishing these procedures, the Commission adopted "confidentiality conclusions" in the

---

1 California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

2 Sen. Bill 1488 (2003-2004 Reg. Sess.) (Stats. 2002, ch. 690).

"IOU Matrix," so that an IOU seeking confidential treatment is required only to demonstrate that the information matches a category specified in the Matrix.[3] While acknowledging the statute does not extend to energy service providers (ESPs),[4] the Commission concluded that "[t]he *process* for dealing with confidential documents should be the same regardless of who claims entitlement to protection."[5] It thus extended its procedures to ESPs, adopting a separate "ESP Matrix," specifying that information would be treated as confidential if the ESP could demonstrate that it matches a category specified in the Matrix.[6]

While Community Choice Aggregation (CCA) providers were authorized before D.06-06-066 was issued,[7] at that time no CCA had yet been formed. Consequently, while the Commission generally stated that the process should apply "whether the producing party is an IOU, an ESP, a future Community Choice Aggregator, or any other entity,"[8] it did not directly address CCAs or provide a "CCA Matrix." Since that time, nineteen (19) CCAs launched in California.[9]

The Commission recently directed CCAs to provide market-sensitive information to the Energy Division. Specifically, D.18-10-019 issued in Phase 1 of the Power Charge Indifference Adjustment (PCIA) proceeding requires CCAs, along with other jurisdictional Load-Serving Entities (LSEs), to report their Resource Adequacy (RA) and Renewable Portfolio Standard (RPS) transactions annually to Energy Division Staff. CalCCA, on behalf of its members, has

---

3 Decision (D.)06-06-066 at 80, Ordering Paragraph 2.
4 *Id.* at 78, Conclusion of Law 16.
5 *Id.* at 52.
6 *Id.* at 80, Ordering Paragraph 2.
7 Assem. Bill No. 117 (2001-2002 Reg. Sess.) (Stats. 2002, ch. 838).
8 *Id.* at 83, Ordering Paragraph 10.
9 *See*, Q1 2019 Update, California Community Choice Association, https://mailchi.mp/cal-cca/calcca-q1-2019-update.

addressed confidentiality of the RA and RPS reports piecemeal, in both the RA and PCIA proceedings.[10]

In light of the new and ongoing reporting requirements, CalCCA requests modification of D.06-06-066 to make clear that the decision's protections apply to CCAs and to provide a "CCA Matrix" to identify protected information.

Rulemaking (R.) 05-06-040, under which D.06-06-066 was decided, was officially closed by D.19-04-012. CalCCA respectfully requests the Rulemaking be reopened to implement the modification to D.06-06-066 requested herein.

II. BACKGROUND

A. Decision 06-06-066 Establishes Procedures for Handling Confidential Procurement-Related Information

In R.05-06-040 the Commission considered the implications of California Public Utilities Code section 454.5(g), which provides:

> [t]he commission shall adopt appropriate procedures to ensure the confidentiality of any market sensitive information submitted in an electrical corporation's proposed procurement plan or resulting from or related to its approved procurement plan, including, but not limited to, proposed or executed power purchase agreements, data request responses, or consultant reports, or any combination of these, provided that the Office of Ratepayer Advocates and other consumer groups that are nonmarket participants shall be provided access to this information under confidentiality procedures authorized by the commission.[11]

The Commission implemented the statute in D.06-06-066 by categorizing procurement data likely to be submitted to the Commission and deeming certain categories of information eligible

[10] Motion for Leave to Submit Information to Staff Under Seal, April 27, 2018 (hereafter, RA Confidentiality Motion); Motion of California Community Choice Association For Leave to Submit Information to Staff Under Seal, January 24, 2019 (hereafter, RPS Confidentiality Motion).

[11] Cal. Pub. Util. Code, § 454.5(g).

for confidential treatment. The categories of information deemed confidential were identified in an "IOU Matrix" and "ESP Matrix" appended to the decision.[12]

It appears the Commission intended in D.06-06-066 to apply the process created by that Decision to confidential information regardless of which type of entity submits the information: "[The] general process should apply whether the producing party is an IOU, an ESP, a future Community Choice Aggregator, or any other entity."[13] However, the matrices used to apply the strictures of D.06-06-066 do not apply to Community Choice Aggregators.[14] Thus, while CCAs were contemplated by the Decision, the mechanism by which a CCA's information would be granted confidential treatment was not specified.

B. CCAs Voluntarily Complied with an Energy Division Data Request for Resource Adequacy Data in 2018 and Were Granted Leave to Submit Confidential, Market-Sensitive Information Under Seal.

In 2018 the Energy Division issued data requests by which CCAs and other LSEs were directed to submit price data for resource adequacy contracts, including the amount of capacity under contract, the amount of system, local, and flexible capacity under contract, and the prices under such contracts (the 2018 RA Data Request).[15] In response to the 2018 RA Data Request CalCCA filed a Motion for Leave to Submit Information to Staff Under Seal on behalf of its members on April 27, 2018 (RA Confidentiality Motion). The RA Confidentiality Motion specifically sought confidential treatment of information regarding the amount of each type of capacity under contract, and the capacity price.

On May 18, 2018, Administrative Law Judge Chiv issued a Ruling granting CalCCA's request (May 18, 2018 Ruling). The ruling provides that CCAs may submit specified categories

---

[12] D.06-06-066, at Appendix 1, Appendix 2.
[13] *Id*. at 83, Ordering Paragraph 10.
[14] *Id.,* at Appendix 1, Appendix 2.
[15] Email from Lily Chow, January 24, 2018.

of information under seal and that such information shall be kept confidential for a period of three years from the date of the RA Data Request, or until a Commission decision supersedes the Ruling.[16] The ruling also includes a succinct summary of the situation: "Decision 06-06-066 addressed confidentiality designations as applied to market-sensitive procurement information, including CCAs, but the Confidentiality Matrices set forth in that decision apply specifically to investor-owned utilities and energy service providers."[17]

The Commission issued D.18-10-019 in the PCIA proceeding in October of 2018. The Decision directs that a weighted average of system, local and flexible RA prices, as published in the Energy Division's annual RA report, will be used to establish the "RA Adder."[18] Accordingly, in February of 2019, the Energy Division issued a data request to all jurisdictional LSEs, seeking "monthly capacity prices paid by [or to] LSEs for every capacity contract covering the 2018-2022 compliance years."[19] CalCCA did not seek further protection for this data on behalf of its members in light of the May 18, 2018 Ruling, which granted confidential treatment to the following categories of information: (1) generic capacity under contract (MW); (2) flexible capacity under contract (MW); (3) capacity price ($kW/month); (4) system or local capacity (MW); and, (5) flexible capacity (MW).[20]

C. CCAs Were Granted Leave to Submit Confidential, Market-Sensitive Information on RPS Transactions Under Seal in the PCIA Proceeding

The PCIA Decision also directs CCAs, as well as the IOUs and ESPs, to submit transaction information to the Commission's Energy Division for the purposes of calculating the

---

16 Administrative Law Judge's Ruling Granting the California Community Choice Association's Request to Submit Information Under Seal (hereinafter, May 18, 2018 Ruling), May 18, 2018, at 2.
17 *Id*. at 1-2.
18 D.18-10-019, at Appendix 1.
19 Email from Simone Brant, February 5, 2019.
20 May 18, 2018 Ruling at 2.

"Renewable Portfolio Standard Adder."[21] The Energy Division is directed to use the information to "calculate a weighted average RPS contract price ($/MWh) for RPS energy"[22] to establish the RPS Adder used to calculate the annual PCIA.[23]

Accordingly, the Energy Division issued a data request to CCAs on January 14, 2019, requesting their RPS transaction data for 2018 (RPS Data Request). As the Decision requires, the requested data includes information regarding the Seller and the resource ID, and the contract price ($/MWh) with and without any time-of-delivery adjustments.[24]

In response to the RPS Data Requests, CalCCA filed a Motion for Leave to Submit Information to Staff Under Seal on behalf of its members on January 24, 2019 (RPS Confidentiality Motion). On March 20, 2019, Administrative Law Judge Atamturk issued a Ruling providing that the procedures and treatment for requesting confidential information applied to ESPs under D.06-06-066 extend to CCAs for the purposes of compliance obligation under Ordering Paragraph 5 of D.18-10-019—related Energy Division data requests, and any other additional related submissions in R.17-06-026, until such time as the ruling is superseded by a Commission decision or ruling (March 20, 2019 Ruling).[25]

III. DISCUSSION

A. Information Sought in the RA and RPS Data Requests Is Confidential, Market-Sensitive Information

The RA and RPS Data Requests seek confidential and highly market-sensitive information: specifically, the contract prices paid and associated data for each CCA's resource adequacy and renewable energy transactions. Disclosure of this information would place the

---

21 D.18-10-019 at 159-161, Ordering Paragraphs 1, 5.
22 *Id*. at 64.
23 *Id*. at 160-161, Ordering Paragraph 5.
24 *Id*.
25 May 18, 2018 Ruling at 2.

contracting CCA at a competitive disadvantage to other LSEs and market participants, and thereby compromise the CCA's ability to procure resources on terms favorable to its ratepayers. Attesting to the market-sensitivity of this information, Appendices 1 and 2 to D.06-06-066 categorize all but summaries of the specific contracts, when submitted by an IOU or ESP, to be treated confidentially for three years from the date of contract or, if earlier, one year following contract expiration.

B. D.06-06-066 Should Be Modified to Provide a Standard Procedure for Treating Confidential and Market-Sensitive Information Submitted By CCAs

Under the May 18, 2018 Ruling in R.17-09-020, specified categories of information submitted by CCAs are granted confidential treatment. The March 20, 2019 Ruling, in R.17-06-026, affirmed that the general matrix process set forth in D.06-06-066 applies to CCAs, referring CCAs to the ESP Matrix in particular.[26] However, the Ruling denied the RPS Motion on procedural grounds and did not specifically address whether the data at issue should be treated as confidential.[27] Although both Rulings are significant steps toward clarity, there are still obvious areas of confusion. Both Rulings are also limited in scope, and neither is capable of applying D.06-06-066 consistently to CCAs for all purposes going forward.

A Commission decision is necessary to resolve, finally and formally, confidentiality issues as applied to submissions by CCAs. Thus, CalCCA respectfully requests on behalf of its members that D.06-06-066 be modified to include CCAs specifically in a new matrix to be attached as Appendix 2A to the Decision. The new matrix, a form of which is attached as Exhibit 1 hereto, is identical to the existing matrix applicable to ESPs. Under the new matrix the

---

[26] *Id*. at 4.

[27] Administrative Law Judge's Ruling Responding to the California Community Choice Association's Motion to Submit Information to Staff Under Seal (March 20, 2019 Ruling), March 20, 2019, at 3.

procedure for handling such information when submitted by CCAs would be identical to the procedure for handling such information when it is submitted by an IOU or ESP.

C. Ordering Paragraph 11 of D.06-06-066 Should Be Modified to Refer to CCAs' Obligations under the California Public Records Act

Ordering Paragraph 11 of D.06-06-066 specifies:

> Intervenor groups that are non-market participants shall not be precluded from access to any ESP or IOU data as long as they agree to a protective order or confidentiality agreement where there is a need to protect the data.[28]

Unlike IOUs or most ESPs, however, CCAs are subject to the California Public Records Act.[29] As such, CCA information is subject to disclosure absent a specific exception provided in the Act.[30] CalCCA respectfully requests that an additional sentence be included in Ordering Paragraph 11 to refer to the CCA's existing obligations, as follows:

> CCAs will make data available in accordance with the California Public Records Act.

IV. THIS PETITION MEETS THE REQUIREMENTS OF RULE 16.4(D)

Rule 16.4(d) requires a petitioner to explain "why the petition could not have been presented within one year of the effective date of the decision." Through this Petition, CalCCA seeks to protect the interests of its current membership, as well as local communities investigating whether to establish CCA programs. Decision 06-06-066 protects from public disclosure certain market sensitive information acquired by IOUs and ESPs as electricity market participants. CalCCA's member CCAs likewise are market participants whose market sensitive information warrants a presumption of confidentiality. Because no CCA had yet been formed in

---

28 D.06-06-066 at 83, Ordering Paragraph 11.
29 Cal. Gov. Code, §§ 6250, *et seq*.
30 *Id*. at § 6253.

2006 when D.06-06-066 was issued,[31] the decision did not expressly address protection of market sensitive information acquired by a CCA. Additionally, modification is supported by the Commission's recent actions requiring all jurisdictional LSEs in D.18-10-019 to report annually on transactions and prices for RA and RPS transactions. For these reasons, this Petition meets the requirements of Rule 16.4(d).

V. CONCLUSION

For the aforementioned reasons, on behalf of its members CalCCA respectfully requests the Commission modify D.06-06-066, as amended by D.07-05-032, D.06-12-030, and D.08-04-023, to make clear that its provisions govern confidentiality of CCA market sensitive information and to specify that CCA data will be included in the attached form of "CCA Matrix" for all purposes. To implement this change, CalCCA respectfully requests R.05-06-040 be reopened.

Respectfully submitted,

Evelyn Kahl

Counsel for California Community Choice Association

January 21, 2020

[31] The first CCA, Marin Clean Energy, was formed in 2010.

EXHIBIT 1
Appendix 2A to D.06-06-066-CCA Matrix

Order Instituting Rulemaking (OIR) 05-06-040 Matrix of Allowed Confidential Treatment Community Choice Aggregator (CCA) Data		
Item	**Public/Confidential Treatment**	**Explanation of Item**
I) Renewables Portfolio Standard (RPS) Information		
A) Renewable Portfolio Standard (RPS) compliance filings required by California Public Utility Commission (CPUC), by CCA	Public	Includes one-time and recurring reporting. Shows current and projected contents of a CCA's RPS portfolios, including sales and resource mix.
B) Annual RPS compliance filings, by CCA	Public	Includes Annual Procurement Target (APT) reporting required in Rulemaking (R.) 04-04-026 and all other required reports.
C) RPS contracts	Contract summaries public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date. Other terms confidential for three years, or until one year following expiration, whichever comes first.[1]	

[1] Where this Matrix allows confidential treatment for a period of time, that period shall begin on the first date a CCA submits the data to the Commission.

Order Instituting Rulemaking (OIR) 05-06-040 Matrix of Allowed Confidential Treatment Community Choice Aggregator (CCA) Data		
Item	**Public/Confidential Treatment**	**Explanation of Item**
II) Resource Adequacy Information		
Detailed load forecasts (both year ahead and month ahead)	Front three years of forecast data confidential	Year ahead data show that CCA has secured adequate generation capacity to cover 90% of its forecast peak load for next year's summer months. Month ahead data show that CCA has secured adequate capacity to cover 100% of its forecast load plus a reserve requirement
III) Load Forecast Information and Data – Electric		
A) Load Servicing Entity (LSE) demand forecasting methodology	Public	General descriptive information regarding the methodology used by LSEs when estimating future expected electric capacity and energy needs.
B) LSE Total Peak Load Forecast - (MW)	Front three years of forecast data confidential.	Each LSE's own forecast of its bundled customer peak load. CCAs file annual and monthly data in CEC IEPR Forms 1.3 (annual sectoral peak demand forecasts) and 1 (monthly peak demand for total CCA peak load)
C) LSE Total Energy Forecast – (MWh)	Front three years of forecast data confidential.	CCAs file annual and monthly data in CEC IEPR Forms 1.3 (annual sectoral energy forecasts) and 2 (monthly energy forecast on a total CCA load basis)
D) Total Peak Demand Load Forecast – Investor-Owned Utility (IOU) Planning Area (MW)	Annual and Quarterly data: Public. Monthly and Daily data: Front three years of forecast data	CCAs file annual and monthly data in CEC IEPR Forms 1.3 (annual forecasts) and 2 (monthly forecasts). When CCA data aggregated with that of other LSEs, can create planning area forecast.

Order Instituting Rulemaking (OIR) 05-06-040 Matrix of Allowed Confidential Treatment Community Choice Aggregator (CCA) Data		
Item	**Public/Confidential Treatment**	**Explanation of Item**
	confidential.	
E) Detailed load forecasts filed in spring for upcoming year, by energy service provider (ESP)	Upcoming year forecast confidential; public once data is one year old.	
IV) Bilateral Contract Terms and Conditions – Electric		
A) Contracts and power purchase agreements between CCAs and IOUs (except RPS)	Contract summaries public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date. Other terms confidential for three years from date contract states deliveries to begin; or until one year following expiration, whichever comes first.	Specific contracts between the IOU and CCA to deliver power to IOUs. The contract information includes the capacity, energy, timing, and pricing terms of the contracts.
B) Expired Power Purchase Agreements (PPAs)	Contract summaries public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date. Other terms confidential for three years from date contract states	Terminated CCA-IOU Power Purchase Agreements under which power is no longer delivered.

Order Instituting Rulemaking (OIR) 05-06-040 Matrix of Allowed Confidential Treatment Community Choice Aggregator (CCA) Data		
Item	**Public/Confidential Treatment**	**Explanation of Item**
	deliveries to begin; or until one year following expiration, whichever comes first.	
C) Bilateral contracts	Contract summaries public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date. Other terms confidential for three years from date contract states deliveries to begin; or until one year following expiration, whichever comes first.	Includes contracts of greater and fewer than 5 years in duration.
~~V)~~ **Recorded (Historical) Data and Information - Electric**		
A) Market purchases of energy and capacity	Public after data are one year old.	

EXHIBIT 2
Decision 06-06-066
Proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs

Conclusions of Law

15. The confidentiality rules applicable to IOUs,~~ and~~ ESPs and CCAs need not be identical.

22. It is reasonable to adopt the IOU Matrix, ~~and~~ ESP Matrix, and CCA Matrix. We balance the need for open decision making and meaningful public participation with the legitimate needs of parties that come before us for confidential treatment of their data as allowed by law.

23. There may be differences between parties that justify different substantive treatment of data. No type of entity (e.g., IOU, ~~or~~ ESP, or CCA) shall receive greater confidentiality for its data merely because it is such an entity.

Ordering Paragraphs

1. Where we find that data are market sensitive pursuant to Pub. Util. Code § 454.5(g) or otherwise entitled to confidentiality protection, in most cases, we adopt a window of confidentiality for Investor-Owned Utility (IOU) and Energy Service Provider (ESP) data that protects it for three years into the future, and one year in the past.

2. We adopt the confidentiality conclusions set forth in the IOU Matrix, ESP Matrix and CCA Matrix attached hereto as Appendices 1, 2, and 2A~~2~~ (collectively Matrix, unless otherwise stated). Where a party seeks confidentiality protection for data contained in the Matrix, its burden shall be to prove that the data match the Matrix category. Once it does so, it is entitled to the protection the Matrix provides for that category. The submitting party must file a motion in accordance with Law and Motion Resolution ALJ-164 or any successor Rule, accompanied with any proposed designation of confidentiality, proving:

   1.) That the material it is submitting constitutes a particular type of data listed in the Matrix,

   2.) Which category or categories in the Matrix the data correspond to, 3.) That it is complying with the limitations on confidentiality specified in the Matrix for that type of data,

4.) That the information is not already public, and

5.) That the data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure.

11. Intervenor groups that are non-market participants shall not be precluded from access to any ESP or IOU data as long as they agree to a protective order or confidentiality agreement where there is a need to protect the data. CCAs will make data available in accordance with the California Public Records Act.

13. With this decision, we commence Phase Two of this proceeding. Respondents shall, and other parties may, file and serve comment on whether it is appropriate for us to develop the following requirements within 30 days of Commission adoption of this decision:

1.) A motion that simply asserts, without explanation, that the data contain trade secrets or "market sensitive" information will denied as incomplete.

2.) A party whose motion has been denied for violation of item 1 that refiles the motion in substantively the same form may be subject to penalties pursuant to § 2107 at the discretion of the Assigned Commissioner, Assigned Administrative Law Judge (ALJ) or Law and Motion ALJ.

3.) A party seeking confidentiality treatment shall provide in its motion, in text or table form, the following information:

a. Legal basis for asserting confidentiality (*e.g.*, § 454.5 (g), trade secret, privilege);

b. If covered by the IOU, ~~or~~ ESP, or CCA Matrix in R.05-06-040, the category/ies into which the data fall, with an explanation of how the data match the category/ies in the Matrix.;

c. Discussion of why the data should be kept under seal;

d. Identification of appropriate procedures short of submitting entire documents under seal or in redacted form, such as partial sealing of documents; partial redaction; aggregation of data to mask individualized, sensitive information; delayed information release (after documents are no longer market sensitive); restriction on personnel with access to documents; use of averages, percentages or annualization of data instead of monthly or hourly data; and issuance of guidelines for parties to follow in producing redacted information (*e.g.*, leaving headings in documents; limiting redactions to figures only; and leaving sufficient information in documents to give other parties notice of what has been redacted).

4.) Parties may not assume that their motions have been granted if the Assigned Commissioner, Assigned ALJ or Law and Motion ALJ do not act on them. The onus shall be on parties to follow up with the Assigned Commissioner, ALJ or Law and Motion ALJ to seek a ruling, if one is not issued within 60 days of filing of the motion.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues	))))))	Rulemaking 12-11-005

OPENING COMMENTS OF MARIN CLEAN ENERGY ON THE PROPOSED DECISION REGARDING THE SELF-GENERATION INCENTIVE PROGRAM REVISIONS PURSUANT TO SENATE BILL 700 AND OTHER PROGRAM CHANGES

David Peffer
BRAUN BLAISING SMITH WYNNE, P.C.
915 L Street, Suite 1480
Sacramento, California 95814
Telephone: (916) 326-5812
E-mail: peffer@braunlegal.com

January 3, 2020

For: Marin Clean Energy

SUBJECT INDEX OF RECOMMENDED CHANGES

Marin Clean Energy recommends the following changes to the Proposed Decision:

1. A specific amount of each Program Administrator's ("PA") administrative budget for the Program Years 2020-2024 must be exclusively dedicated to SGIP Equity Marketing, Education, and Outreach ("ME&O") efforts under the Self-Generation Incentive Program ("SGIP").
2. The Commission should significantly increase the level of dedicated funding for the SGIP Equity ME&O activities. The appropriate level of funding could be discussed with stakeholders in the SGIP ME&O workshop to be held on January 14, 2020.
3. Each PA should strive towards fully spending its annual ME&O budget allocation and should provide the Commission's Energy Division with an annual breakdown of its ME&O expenditures and program enrollment results.
4. Each PA's dedicated Equity ME&O budget should distinguish between general, mass-market ME&O efforts and targeted, community-specific outreach efforts and should establish a minimum percentage of ME&O funds that must be directed to community outreach.
5. All CCAs should be given the opportunity to become the local community outreach partner under the SGIP Equity ME&O Plan in their service area. CCAs interested in becoming SGIP Equity ME&O partners should be given the opportunity to submit community outreach plans plans to the Energy Division. If the Energy Division concludes that the CCA's plan is consistent with SGIP program goals and requirements, it should approve the plan and grant the CCA access to a proportional share of Equity ME&O funds.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues)	Rulemaking 12-11-005

OPENING COMMENTS OF MARIN CLEAN ENERGY

ON THE PROPOSED DECISION

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE")[1] hereby submits the following opening comments on the December 11, 2019 *Proposed Decision of Commissioner Rechtschaffen on Self-Generation Incentive Porgram Revisions Pursuant To Senate Bill 700 And Other Program Changes* ("PD") in the above-captioned proceeding, Rulemaking ("R.") 12-11-005.

MCE submits these comments for two fairly narrow purposes. First, MCE offers its strong support for many of the PD's updates to the SGIP, particularly the PD's expansion and improvement of the Equity and Equity Resiliency Program ("ERP"). Second, MCE proposes specific refinements to the ERP's ME&O budgets and initiatives. Like the Commission, MCE recognizes the critical importance of providing vulnerable customers and critical facilities with resiliency resources before the start of next fire season. Achieving this ambitious goal in a highly

[1] MCE, California's first Community Choice Aggregator, 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 serving approximately 1,000 MW peak load, providing electricity generation services to more than 1.1 million people in 34 communities across Marin, Contra Costa, Napa and Solano counties.

compressed timeframe will require an intense outreach effort that is carefully targeted to the customers, communities, and critical facilities that are most vulnerable to wildfires and Public Safety Power Shutoff ("PSPS") outages. Realistically, this intense ME&O effort is only possible with adequate funding and with the full and active involvement of local partners, including Community Choice Aggregators ("CCAs").

MCE is concerned that the PD as currently worded: 1) does not provide sufficient funding for SGIP Equity ME&O efforts; and 2) does not require that SGIP PAs work with local partners to ensure successful ME&O initiatives. MCE provides specific recommendations for remedying these issues below. These recommendations are reflected in the proposed modifications to the PD's Findings of Fact, Conclusions of Law, and Ordering Paragraphs set forth in Appendix A to these comments.

I. COMMENTS ON THE PROPOSED DECISION

A. MCE Strongly Supports the PD's Updates to the SGIP Equity Resiliency Program

Overall, MCE views the PD as a bold and proactive step towards the critical goals of improving the resiliency of vulnerable customers and critical facilities through the installation of behind the meter energy storage and renewable generation. In particular, MCE expresses its strong support for the following aspects of the PD:

1. Authorizing the annual collection of $166 million from ratepayers to fund the SGIP for the Prorgam Years ("PYs") 2020-2024.
2. Allocating 63% of SGIP incentive funds to the equity resiliency budget.
3. Expanding the definition of eligible residential customers and critical facilities under the ERP.

B. The PD Should Be Amended to Ensure Adequate ERP ME&O Funding

SGIP ME&O funding is embedded in each PA's "administrative" budget.[2] As currently worded, the PD proposes the following administrative budgets for each of the four SGIP PAs for the PYs 2020-2024:

- For Southern California Gas ("SocalGas"), the PD approves an annual administrative budget of 7% of the total 2020-2024 annual SGIP budget ($1.04 million annually).
- For the Center for Sustainable Energy ("CSE"), the PD approves an annual administrative budget of 10% of the total 2020-2024 annual SGIP budget ($2.16 million annually).
- For PG&E, the PD approves a total administrative budget of $26.7 million for 2020-2024 ($5.34 million annually). The PD requires that this money be taken from accumulated unspent administrative funds from prior SGIP PYs.
- For SCE, the PD approves a total administrative budget of $31.6 million for 2020-2024 ($6.32 annually). The PD requires that this money be taken from accumulated unspent administrative funds from prior SGIP PYs.

These administrative funds must cover all program implementation costs, including, but not limited to, PA's program administration costs, incentive application processing, ME&O efforts, as well as program evaluation, measurement and verification.

MCE is concerned that the SGIP PD does not establish clear guidelines on what percentage of the SGIP's administrative budget should be used for Equity ME&O efforts. D.19-09-027 established the SGIP Equity ME&O Plan and determined that PAs shall allocate no more than 10 percent of their accumulated unused administrative budgets to fund the plan.[3] The Decision does

[2] See D.11-09-015 at 57.
[3] See D.19-09-027 at 56.

not provide any further detail if this is a statewide allocation or if each PA shall use 10% of their respective accumulated unused administrative budgets to fund SGIP Equity ME&O efforts in their territory. The Decision also does not specify if this budget allocation was intended to only fund the first year of SGIP Equity ME&O efforts or all future program years.

MCE strongly urges the Commission to allocate the appropriate level of funding to SGIP Equity ME&O efforts for all future PYs in order to achieve meaningful SGIP ERP participation and make a measurable difference in reducing the impacts of future PSPS outages and wildfires. MCE cautions that simply allocating 10% of the approved administrative budgets to SGIP Equity ME&O efforts will not be enough to conduct the required intensive and targeted ME&O efforts. For PG&E for example, a 10% ME&O allocation would lead to an annual budget of approximately $534,000 to cover marketing, education and outreach efforts in the entirety of PG&E's distribution service territory. This level of funding is not adequate to achieve meaningful enrollment in the SGIP's Equity and Equity Resiliency Program over the next 5 years. As a general matter, outreach to vulnerable customers has been shown to be more costly and time consuming than to general market populations. Outreach efforts will require significant work identifying vulnerable customers located in eligible areas, educating these customers, and encouraging program enrollment. Even though equity resiliency incentives are expected to cover the full cost of residential systems, industry and local community partners are warning that customer recruitment will be extremely challenging due to complex customer eligibility requirements, a lack of data regarding eligible customers, and trust and conversion challenges associated specifically with vulnerable customers.

The PD's lack of a specific Equity ME&O funding allocation is particularly concerning in light of the SGIP's low enrollment rates in recent years. The SGIP PAs do not have a strong track-record of effectively utilizing SGIP administrative funds to drive SGIP participation.[4] In part due to the lack of ME&O efforts and low public awareness of the SGIP, the program was grossly underutilized during the 2017-2019 period, resulting in over $400 million in unspent program funds as of September 2019.[5]

In order to remedy this issue, MCE proposes several changes to the PD:

1. A specific amount of each PA's administrative budget for the Program Years 2020-2024 must be exclusively dedicated to SGIP Equity ME&O efforts.
2. The Commission should significantly increase the level of dedicated funding for the SGIP Equity ME&O activities. The appropriate level of funding could be discussed with stakeholders in the SGIP ME&O workshop to be held on January 14, 2020.
3. Each PA should strive towards fully spending its annual ME&O budget allocation and should be required to provide the Energy Division with an annual breakdown of its ME&O expenditures and program enrollment results.
4. Each PA's dedicated Equity ME&O budget should distinguish between general, mass-market ME&O efforts and targeted, community-specific outreach efforts, and should establish a minimum percentage of ME&O funds that must be allocated to community outreach.

---

[4] As the Commission noted in D.19-09-027, as of September 2019, the SGIP PAs had accumulated a total of total $70.2 million in accumulated administrative funds. For 2017 – 2019, PG&E collected $33.9 million in administrative funds for the SGIP program. However, during this timeframe PG&E spent only $5.5 million on SGIP administration (which includes ME&O acivities), leaving PG&E with over $28.3 million in unspent administrative funds.

[5] D.19-09-027 at 85-86.

C. The PD Should *Require* the SGIP PAs to Collaborate with Local Government and Community Partners under the SGIP Equity ME&O Plan and Make the Appropriate Level of Funding Available for Such Efforts

For the SGIP ERP to succeed, it is essential that the SGIP PAs partner with local agencies like CCAs and community based organizations ("CBOs") on the community outreach efforts under the SGIP Equity ME&O Plan. To date, the Legislature and the Commission have acknowledge the importance of local community partners for outreach under the SGIP Equity ME&O Plan in several instances but have stopped short of *requiring* SGIP PAs to work with local government and community partners. As the PD notes, AB 1144 determined that the Commission must prioritize funding for SGIP projects that meet three criteria, including coordination with electrical corporation serving the customers' community and *relevant local governments*.[6] CCAs are Electric Service Providers and relevant local government agencies. Similarly, in D.19-09-027, the Commission stated that "local governments and CCAs may be appropriate to implement components of the [SGIP Equity ME&O] Plan, depending on the activities that emerge via planning discussions."[7][8]

MCE believes that the Commission errs in not requiring SGIP PAs to coordinate with local government agencies and CBOs in the implementation of the SGIP Equity ME&O Plan. CCAs are ideally positioned to implement these community outreach efforts for many reasons.

---

[6] PD at 50.

[7] D.19-09-027 at 58.

[8] Although the Commission suggested in the Decision that the PAs hold a workshop on their ME&O Plans to facilitate the recommended planning discussions, no workshops were held before the SGIP PAs filed the Equity ME&O Plan for residential customers in Pacific Gas and Electric Company Advice Letter 4191-G/5714-E, Southern California Edison Company Advice Letter 4127-E, Southern California Gas Company Advice Letter 5555-G, and Center for Sustainable Energy Advice Letter 106-E, filed on December 17, 2019. There is now a workshop scheduled for January 14, 2020 in preparation of the filing of a comprehensive SGIP Equity ME&O Plan in February. However, MCE cautions that one workshop may not be sufficient to develop a thoughtful and effective ME&O Plan between SGIP PAs and stakeholders. To accelerate the process, MCE will be submitting a response to the SGIP PAs's proposed ME&O Plan for residential customers on January 6, 2020, proposing a community outreach plan for residential customers in our service area.

First, CCAs serve some of the communities most severely impacted by wildfires and PG&E's PSPS events. As such, CCAs have a strong interest in ensuring that their customers and communities are fully informed about the SGIP ERP, and get access to support and incentives to improve the resiliency of their homes and critical facilities before the next fire season.

Second, as community-based and customer-focused public agencies, CCAs have close ties to our communities, customers and member local governments and have a good understanding of how to reach vulnerable customer segments. MCE is already effectively engaging with tens of thousands of customers and partners relevant to the SGIP equity budget and would be able to quickly ramp up to support SGIP equity ME&O efforts through existing outreach channels: community and energy equity CBOs, local community centers, libraries, local public agencies including town and city offices, local fire departments, offices of emergency services ("OES"), schools, and other public health and emergency service partners. In addition, many CCAs are already aggressively pursuing their own programs and efforts targeted at income qualified customers with resiliency needs, and can leverage these existing programs, connections and resources to spread the word about the availability of SGIP equity and equity resiliency incentives. For example:

- MCE has allocated $3 million in this fiscal year alone to support resiliency initiatives at facilities that provide critical community services during PSPS events. Under this initiative, MCE has been actively engaging with its local government and OES partners to identify the facilities that were critical in maintaining community support during the 2019 PSPS events. To date, MCE has identified more than 60 critical facilities across MCE's service area that are prime candidates for SGIP incentives.
- In December 2019, MCE published a request for proposals ("RFP") to identify qualified organizations to support MCE in the development of energy storage resiliency

programs for residential customers.[9] The focus of the RFP is to provide resiliency solution for MCE's most vulnerable customers, including, but not limited to, low-income customers, customers located in disadvantaged communities, and customers with a medical need.

- MCE already serves income-qualified and disadvantaged communities with a wide range of energy efficiency, renewable energy and clean transportation offerings. MCE offers an electric vehicle rebate program which provides rebates for new electric vehicle purchases for low income individuals. In the energy efficiency realm, MCE runs the Low-Income Families and Tenants ("LIFT") program under the umbrella of California's Energy Savings Assistance ("ESA") program which provides no-cost home assessments, technical assistance, rebates and direct installation of energy saving measures for affordable multifamily properties. To date, MCE has worked with 24 properties representing 1,482 units in the LIFT program. Under this program, MCE also leverages other programs geared at energy, health and safety improvements in homes such as MCE's Multifamily Energy Savings Program and the Green & Healthy Homes Initiative ("GHHI") Marin which combines energy efficiency upgrades with other health, safety and comfort measures. Finally, MCE complements solar rebates for low income homeowners and affordable multifamily properties offered by the state with additional rebates. To date, over 250 income qualified homeowners and 2 affordable housing multifamily properties have installed solar through MCE's low-income solar program.

[9] MCE's RFP can be found on MCE's website here.

Given CCAs' local knowledge, community connections, close working relationships with local governments, and demonstrated willingness to dedicate significant funds to resiliency initiatives, the Commission should modify the PD to *require* SGIP PAs to work with CCAs on community outreach under the SGIP Equity ME&O Plan and to allow interested CCAs to access proportional shares of SGIP ME&O funding to amplify their own local outreach. More specifically, MCE recommends that all CCAs be given the opportunity to become the local community outreach partner under the SGIP Equity ME&O Plan in their service area. CCAs interested in becoming SGIP Equity ME&O partners should be given the opportunity to submit community outreach plans plans to the Energy Division. If the Energy Division concludes that the CCA's plan is consistent with SGIP program goals and requirements, it should approve the plan and grant the CCA access to a proportional share of Equity ME&O funds.

IV. CONCLUSION

MCE thanks the Commission for its consideration of these comments. For the reasons discussed herein, MCE respectfully ask that the Commission adopt the modifications and additions to the PD's Findings of Fact, Conclusions of Law, and Ordering Paragraphs set forth in Appendix A.

Dated: January 3, 2020

Respectfully submitted,

/s/ David Peffer

David Peffer
BRAUN BLAISING SMITH WYNNE, P.C.
915 L Street, Suite 1480
Sacramento, California 95814
Telephone: (916) 326-5812
E-mail: peffer@braunlegal.com

For: Marin Clean Energy

APPENDIX A: APPENDIX OF PROPOSED MODIFICATIONS

(Modifications to existing language: deletions are shown as strike-outs; additions are underlined and italicized)

MODIFICATIONS TO CONCLUSIONS OF LAW:

New Conclusion Of Law:

It is reasonable and prudent for the Commission to require that a specific amount of each Program Administrator's administrative budget for the Program Years 2020-2024 be exclusively dedicated to SGIP Equity Marketing, Education, and Outreach efforts.

New Conclusion Of Law:

The Commission should significantly increase the level of dedicated funding for the SGIP Equity ME&O activities.

New Conclusion Of Law:

It is reasonable and prudent for the Commission to encourage each PA to fully spend its annual ME&O budget allocation and to provide the Commission's Energy Division with an annual compliance filing providing a breakdown of its ME&O expenditures and program enrollment results.

New Conclusion Of Law:

It is reasonable to require that each PA's dedicated Equity ME&O budget distinguish between general, mass-market ME&O efforts and targeted, community-specific outreach efforts, and to establish a minimum percentage of ME&O funds that must be directed to community outreach.

New Conclusion Of Law:

It is reasonable to allow interested CCAs to act as the local community outreach partner under the SGIP Equity ME&O Plan in their service area. Interested CCAs should have the opportiunity to submit community outreach plans to the Energy Division, and if the Energy Division concludes that the CCA's plan is consistent with SGIP program goals and requirements, it should approve the plan. CCAs with approved plans should be granted access to a proportional share of Equity ME&O funds.

MODIFICATIONS TO ORDERING PARAGRAPHS:

New Ordering Paragraph:

Within two weeks of the effective date of this Decision, the Energy Division shall provide the Commission with recommendations regarding: 1) the appropriate amount of each PA's administrative budget that should be dedicated to SGIP Equity ME&O activities for the Program Years 2020 - 2024; 2) the minimum percentage of each PA's Equity ME&O funds that must be directed towards targeted community outreach rather than mass-market outreach.

New Ordering Paragraph:

On January 1 of each year from 2021-2025, each PA shall be requird to submit a compliance filing via Tier 2 advice letter providing the Commission's Energy Division with an annual breakdown of its ME&O expenditures and program enrollment results.

New Ordering Paragraph:

Within three weeks of the effective date of this Decision, any CCA interested in becoming an SGIP Equity ME&O partner for 2020 shall submit a community outreach plan to the Energy Division. The Energy Division shall review each community outreach plan for compliance with SGIP program goals and requirements, and shall approve all plans that comply with SGIP program goals and requirements. PAs shall grant CCAs with approved plans access to a proportional share of SGIP Equity ME&O funds. CCAs interested in becoming SGIP Equity ME&O partners for future years in the 2021-2024 program period shall submit community outreach plans to the Energy Division no later than January 1 of the Program Year.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues	)))))	Rulemaking 12-11-005

REPLY COMMENTS OF MARIN CLEAN ENERGY ON THE PROPOSED DECISION REGARDING THE SELF-GENERATION INCENTIVE PROGRAM REVISIONS PURSUANT TO SENATE BILL 700 AND OTHER PROGRAM CHANGES

David Peffer
BRAUN BLAISING SMITH WYNNE, P.C.
555 Capitol Mall, Suite 570
Sacramento, California 95814
Telephone: (916) 326-5812
E-mail: peffer@braunlegal.com

January 8, 2020

For: Marin Clean Energy

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues)	Rulemaking 12-11-005

REPLY COMMENTS OF MARIN CLEAN ENERGY ON THE PROPOSED DECISION REGARDING THE SELF-GENERATION INCENTIVE PROGRAM REVISIONS PURSUANT TO SENATE BILL 700 AND OTHER PROGRAM CHANGES

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE")[1] hereby submits the following reply comments on the December 11, 2019 *Proposed Decision of Commissioner Rechtschaffen on Self-Generation Incentive Porgram Revisions Pursuant To Senate Bill 700 And Other Program Changes* ("PD") in the above-captioned proceeding, Rulemaking ("R.") 12-11-005. In these reply comments, MCE addresses three issues raised in the respective opening comments of GRID Alterantives ("GRID") and Southern California Edison Company ("SCE").

I. REPLY COMMENTS

A. MCE Supports, With Slight Modifications, GRID's Proposal to Fund Community Outreach Organizations Under the Equity ME&O Program

In its opening comments, GRID proposes that a portion of the Self Generation Incentive Program ("SGIP") Program Administrators' ("PA") unused administrative budgets be allocated to community based organizations ("CBOs") and low-income solar incentive program PAs in order to allow them to conduct marketing, education, and outreach ("ME&O") activities in support of

[1] MCE, California's first Community Choice Aggregator, 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 serving approximately 1,000 MW peak load, providing electricity generation services to more than 1.1 million people in 34 communities across Marin, Contra Costa, Napa and Solano counties.

SGIP equity programs.[2] MCE supports this proposal, with the following slight modifications and clarifications.

First, SGIP ME&O budget allocations should be set proportional to the PA's total administrative budget allocation for future program years, rather than be based on unused accumulated administrative budgets to date. This will ensure that ME&O budgets are set proportional to total admin and incentive funds for PYs 2020-2024, not the (rather arbitrary) amount of unspent funds accumulated by a given PA. While the Commission proposes in the PD that Pacific Gas and Electric ("PG&E") and Southern California Edison ("SCE") utilize accumulated unspent administrative funds to cover admin costs for program years ("PYs") 2020-2024,[3] Southern California Gas Company ("SoCalGas") and the Center for Sustainable Energy ("CSE") get access to additional administrative funds from the SGIP collections for PYs 2020-2024.[4] [5]

Second, MCE supports GRID's proposed allocation of 4% of unused administrative funds to low-income solar PAs, but *strongly urges the Commission to make significantly more ME&O funding available for other community outreach partners including CBOs, local governments, tribal communities, and Community Choice Aggregators ("CCAs") than the 1% allocation that GRID proposes*.[6] MCE strongly agrees with GRID that an effective ME&O plan for the SGIP Equity and Equity Resiliency Program ("ERP") will require significant ME&O engagement by partners that are known and trusted by their communities, are able to create materials that are in the languages spoken by their communities, and are able to travel to communities for direct engagement. MCE shares GRID's concern that "many low-income and rural customers do not have internet access, and do not trust or respond to mailers if the outreach entity does not already have a presence in the community."[7] Additionally, outreach to eligible customers must be implemented immediately and efficiently to be able to engage eligible customers before the next fire season. These concerns highlight the inadequacy of centralized mass-marketing proposed by

---

2 GRID Opening Comments at11.
3 PD at 23.
4 PD at 24.
5 In summary, the PD proposes the following admin budgets for the SGIP PAs for PYs 2020-2024: $26,708,673 for PG&E, $31,589,564 for SCE, $10,790,000 for CSE, and $5,230,000 for SoCalGas. *See* PD at 23-24 (proposing administrative budgets).
6 GRID Opening Comments at 11.
7 GRID Opening Comments at 10.

the SGIP PAs to date, and the need to partner with – and adequately fund – community outreach partners to implement more focused ME&O strategies. This kind of on-the-ground community outreach to a diverse target customer population will require significantly more funding than the 1% allocation proposed by GRID in Opening Comments.

MCE proposed in Opening Comments that more than 10% of SGIP administrative funds must be allocated to Equity ME&O activities in the future.[8] In response to GRID's Opening Comments, MCE offers the following further elaboration on its proposed Equity ME&O allocation:

- At least 30% of SGIP administrative funds for PYs 2020-2024 should be set aside for Equity ME&O.
- At least two-thirds of this Equity ME&O allocation (or at least 20% of the total admin budget) should be designated to community outreach, implemented through community partners.

The following table displays a summary of MCE's proposed Equity ME&O budget allocation for PYs 2020-2024:

Table 1: Proposed Equity ME&O Budget Allocations for PYs 2020-2024

SGIP PA	**Total Admin Budget Allocation**	**Equity ME&O Budget Minimum Allocation**	**Community Outreach Budget Minimum Allocation**
PG&E	$26,708,673	$8,012,601	$5,341,734
SCE	$31,589,564	$9,476,869	$6,317,912
CSE	$10,790,000	$3,237,000	$2,158,000
SoCalGas	$5,230,000	$1,569,000	$1,046,000
Total admin funds PYs 2020-2024	**$74,318,237**	**$22,295,471**	**$14,863,647**

In PG&E's service territory, this ME&O budget allocation would lead to an *annual* Equity ME&O allocation of approximately $1.6 million, and an annual community outreach allocation of

8 MCE Opening Comments at 4.

approximately $1 million shared by all community outreach partners. MCE believes that this is a minimum appropriate amount of funding considering the urgency of the need.

MCE is proposing this ME&O budget allocation for PYs 2020-2024 as a basis for discussion and suggests that further discussions will be held among stakeholders during the SGIP ME&O workshop on January 14.

Third, MCE supports GRID's position that third-party ME&O partners should have "experience conducting successful marketing and education to low-income, disadvantaged, rural and tribal communities, as part of the customized equity ME&O plan."[9] MCE has proposed in its Opening Comments that CCAs interested in becoming a SGIP ME&O community outreach partner should submit a "Community Outreach Plan" to the Commission's Energy Division for approval before accessing program funds.[10] This proposal could be extended beyond CCAs, and submitting a Community Outreach Plan could be the way for interested community partners to demonstrate their experience conducting successful marketing and education to vulnerable customers as proposed by GRID.

B. MCE Supports GRID's Proposed Modification To Customer Eligibility Criteria Under The Equity Resiliency Program

The PD would expand ERP eligibility to also include residential customers who have experienced two or more discrete PSPS events.[11] In opening comments, a number of parties argued for additional expansion of the SGIP ERP eligibility. For instance, Tesla argues that all customers located within "an area identified by the utilities as at risk of being impacted by a Public Safety Power Shutoff" should qualify for ERP funding.[12] While MCE sympathizes with Tesla's desire to provide all at-risk customers with resiliency resources, MCE disagrees with this proposal. The ERP is a program with limited funding, and these resources must be carefully targeted and deployed to the customers, communities, and critical facilities that are at the highest risk of experiencing prolonged PSPS outages. Based on the IOUs' prior statements, a large percentage of their customers are *potentially* at risk of experiencing a PSPS outage. Making all such customers

9 GRID Opening Comments at 11.
10 MCE Opening Comments at 9.
11 PD at 36-37.
12 Tesla Opening Comments at 3.

eligible for ERP funding would prevent the funding from going to those customers with a clear, proven risk of PSPS outages.

As the PD recognizes, there is a clear need to develop more accurate measures of PSPS risk and more sophisticated eligibility criteria in the future.[13] Until such criteria are developed, MCE supports GRID's proposal that ERP eligibility be expanded to customers that have experienced *one* PSPS outage as the best and most reasonable "middle ground" approach. Even a single PSPS outage is a significant threat to vulnerable customers, particularly medical baseline and life support customers who rely on electricity for medical purposes. 3,533 of the approximately 12,500 medical baseline customers in MCE's service area experienced two or more discreet PSPS events in 2019. An additional 2,730 medical baseline customers experienced "only" one discreet PSPS event in 2019. This is a large number of vulnerable customers that should have access to SGIP equity resiliency incentives.

Further, GRID's proposal would ensure that customers that have experienced a single, very high-impact and long-duration PSPS outage are not excluded from eligibility while customers that have experienced two or more relatively short-duration outages are eligible.

IV. CONCLUSION

MCE thanks the Commission for its consideration of these comments.

Dated: January 8, 2020

Respectfully submitted,

/s/ David Peffer

David Peffer
BRAUN BLAISING SMITH WYNNE, P.C.
915 L Street, Suite 1480
Sacramento, California 95814
Telephone: (916) 326-5812
E-mail: peffer@braunlegal.com

For: Marin Clean Energy

[13] *See* PD at 38-39.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PORTFOLIO AND RELATED POLICY ACTIONS

Irene K. Moosen
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
415.587.7343
regulatory@cal-cca.org

Director, Regulatory Affairs
California Community Choice Association

Evelyn Kahl
Ann Springgate
Benjamin Ellis
Buchalter, A Professional Corporation
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
ekahl@buchalter.com

Counsel to the California Community Choice Association

January 6, 2020

Table of Contents

TABLE OF ACRONYMS

ABB	Asea Brown Boveri
AWEA	American Wind Energy Association
CalCCA	California Community Choice Association
CAISO	California Independent System Operator
CEC	California Energy Commission
CESA	California Energy Storage Association
CCA	Community Choice Aggregator
ELCC	Effective Load Carrying Capability
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt Hour
IOU	Investor Owned Utility
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MMT	Million Metric Tons
MW	Megawatt
MWh	Megawatt Hour
OOS	Out-of-State
PCM	Production Cost Modeling
PG&E	Pacific Gas and Electric Company
PSP	Preferred System Portfolio
RA	Resource Adequacy
RSP	Reference System Portfolio
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
WECC	Western Electricity Coordinating Council

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING
SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PORTFOLIO

The California Community Choice Association[1] submits these Reply Comments in response to the *Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio* issued on November 6, 2019 (Ruling) and the November 19, 2019, *E-mail Ruling Responding to Southern California Edison Request for Extension of Time to File Comments on Proposed Reference System Portfolio and Related Policy Actions*.

I. INTRODUCTION

Parties' comments on the Ruling offer insights and recommendations that will enhance the effectiveness of the 2019-2020 Integrated Resource Planning cycle. The breadth of comments highlight the need for additional time to allow both Staff and load-serving entities to explore these recommendations and integrate the results of this exploration in modeling and IRP plan preparation. With a schedule extension in mind, CalCCA offers the following recommendations:

---

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

- ✓ **Greenhouse Gas Reductions**. CalCCA supports adoption of an RSP that will achieve the state's climate goals, and observes that many CCAs intend to reduce carbon in their portfolios at a pace faster than envisioned by a 46 MMT scenario. If the 46 MMT GHG emissions constraint does not ensure that climate goal achievement, as SCE has concluded, then a more restrictive target will be necessary. Further review of SCE's conclusions is warranted, however, before replacing Staff's 46 MMT RSP with SCE's 38 MMT scenario.

- ✓ **Plan Aggregation.** CalCCA agrees with SCE that a better understanding of the aggregation process would benefit all parties, increasing the likelihood of a successful aggregation and reducing the strain on Staff resources in this process.

- ✓ **Justifying Portfolio Deviations.** SDG&E provides reasonable examples of ways in which an LSE should be permitted to justify deviations from the RSP. Staff should adopt the illustrations, augmented by CalCCA's recommendations, as reasonable justifications for deviations but maintain receptiveness to other reasonable justifications.

- ✓ **Retention of Gas-Fired Resources.** CalCCA, like other parties, continues to support a swift reduction in reliance on natural gas fired resources to reduce their effects on California's climate goals and disadvantaged communities, but recognizes the need to pace the reduction to avoid placing reliability at risk. Addition of a criteria pollutant metric proposed in CalCCA's Opening Comments will facilitate California's ability to understand the impact of any gas-fired resources through the transition to a carbon-free electricity supply.

- ✓ **Battery Storage ELCC Curve.** Staff's analysis assumes a declining ELCC curve for battery storage as penetration increases. Parties' comments take opposing views on this issue, suggesting that further evaluation of the curve would improve the outcome of this IRP cycle.

With these concerns and others raised in its Opening Comments, CalCCA proposes that Staff hold a two-day workshop in late January. The workshop should aim to:

- Assess the ability of Staff's 46 MMT and SCE's 38 MMT scenarios to meet climate goals;
- Develop more reasonable import assumptions;
- Consider the need for Staff's proposed 2,000 MW of generic effective capacity
- Develop metrics for criteria pollutant emissions;
- Examine differing points of view on battery storage curves; and,
- Explain the steps required in Staff's aggregation process, highlighting in greater detail the problems encountered in the last IRP cycle.

II. REPLY COMMENTS

A. Extend the Procedural Schedule

PG&E[2] and SDG&E[3] reasonably propose to extend the procedural schedule to provide for LSEs' submission of IRP plans by roughly three months. The time between informal release of RESOLVE scenarios and the filing date for 2017-2018 cycle was over 12 months;[4] in this cycle, the schedule has been compressed to seven months. Three additional months would at least partly address this gap, facilitating the development of more robust IRP plans while still providing sufficient time for the Commission to adopt a Preferred System Portfolio by March 1, 2020. The Commission should extend the schedule, requiring LSEs to submit their IRP plans on or before August 1, 2020.

The extension would provide clear benefits to the plan development process. First, a significant share of IRP development is contingent on the release of CEC IEPR load forecasts, which have not yet been released. Since the Commission does not currently plan to allow LSEs to utilize alternatives to the CEC IEPR data as modeling assumptions, LSEs cannot feasibly start the modeling and analysis until the IEPR update has been formally adopted. Second, three additional months would allow additional time for portfolio development, analysis, model modification, stakeholder discussion, and IRP plan preparation. This analysis is critical for LSEs to develop IRPs that reflect their unique portfolio needs and circumstances, which will require determining and planning for uncontracted RPS positions, identifying and considering demand-

---

2 *Opening Comments of Pacific Gas and Electric Company (U 39E) to Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (PG&E Opening Comments), Dec. 17, 2019, at 17 (proposing a July 31, 2020 submission date).

3 *Comments of San Diego Gas & Electric Company (U 902 E) in Response to Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions*, (SDG&E Opening Comments), Dec. 17, 2019, at 5 (proposing an August 1, 2020 submission date)

4 *See* PG&E Opening Comments at 17.

side management opportunities, and ensuring alignment with local policy obligations. Third, the Commission has expressed concerns that LSEs evaluate their impacts to the operation of the grid, which also takes modeling time and effort. Fourth, since CCAs are public agencies, CCA portfolio development must include time for stakeholder discussion and feedback before presentation to CCA boards in public meetings for approval. For example, four CCAs (Clean Power Alliance, San Jose Clean Energy, Peninsula Clean Energy, and East Bay Community Energy) are jointly developing their portfolios to ensure better integration of larger shares of load with robust modeling and stakeholder input. These CCAs are well advanced in their planning and preparation but estimate needing through June 2020 to complete both the requisite modeling, community engagement, and individual CCA board review and approval.[5] Finally, a schedule extension will allow Staff to integrate the output of the workshops proposed by CalCCA in its RESOLVE and SERVM modeling and allow LSEs to reasonably align their plans.

CalCCA understands that significant time is required between the submission of the IRPs and adoption of the Preferred System Portfolio. However, a three-month schedule extension, as proposed by other parties, would allow the Commission 30 weeks to compile and evaluate IRPs and adopt and submit a Preferred System Portfolio, relative to the 38 weeks required in the 2017-2018 IRP cycle. Given the significant IRP aggregation experience gained by parties and staff since the last cycle, coupled with standardized inputs and the process improvements to IRP development and aggregation proposed in this cycle, should provide sufficient time to submit a Preferred System Portfolio to the CAISO by March 1, 2021.

[5] Appendix A provides an illustrative timeline based on the timeline for the development of the joint CCA IRP effort assuming the release of load inputs on January 22, 2019 and a Reference System Portfolio adoption date of March 26, 2020, as indicated in ALJ Fitch's November 19, 2019 email to the IRP Service List.

CalCCA acknowledges that LSEs have been directed to provide an update on their incremental system RA procurement by May 1, 2020, pursuant to Decision 19-11-016, and it is not CalCCA's intention to delay that reporting and procurement obligation. If the Commission does delay the submission of individual LSEs' IRPs to August 1, 2020, CalCCA recommends that the staff provide interim reporting templates for LSEs to submit their update on May 1, 2020.

B. Provide a Default List of Reasonable Justifications for LSE Deviation from the RSP

CalCCA's Opening Comments proposed that Staff permit CCA showings of conflicting requirements mandated or directed by local authorities as an acceptable justification for deviation from the RSP.[6] CalCCA also suggested that qualitative "analysis demonstrating portfolio compliance with overarching policy goals such as decarbonization and reliability, such as PCM assumptions and outputs"[7] should also be considered in assessing RSP deviations.

SDG&E's Opening Comments further illustrate reasonable ways in which an LSE could justify departures from the RSP. As proposed by SDG&E,[8] an LSE could show:

- Past Least Cost, Best Fit solicitations have shown that a resource type proposed in the RSP does not typically fare well into the LSE's prior solicitations;
- Knowledge of local permitting challenges, code restrictions/requirements, or other regional issues indicate that a certain resource type will be more or less successful than what was assumed in the RSP;
- Insights into regional resource development opportunities that could have long-term potential benefits but differ from near-term planning targets; and,

---

6 *California Community Choice Association Comments on Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (CalCCA Opening Comments), Dec. 17, 2019, at 41.

7 *Id*. at 41.

8 SDG&E Opening Comments at 30.

- Competing procurement requirements, like Local RA obligations, that make certain resources more valuable than others.

CalCCA agrees with SDG&E that these justifications should be accepted as reasonable in Staff's evaluation of an LSE's deviation from the RSP. The Commission should expressly adopt these justifications along with CalCCA's recommendations in Opening Comments to permit CCA showings of conflicting requirements mandated or directed by local authorities as presumed acceptable justifications for deviation from the RSP, [9] while remaining open to other potential showings.

C. Adopt a Criteria Pollutant Metric to Minimize Impacts of Retained Natural Gas Fired Generation on Disadvantaged Communities

CalCCA members strongly support a swift transition to a carbon-free electricity supply across California and, in many cases, intend to move more quickly than the goals that will be reflected in the RSP. The transition is critical to meet the state's climate goals and to reduce or eliminate impacts on disadvantaged communities in which some of these resources are located. Parties' comments, however, reveal continuing controversy regarding the need for natural gas-fired resources, and more analytical rigor is required to advance the debate.

Calpine asserts, for example, that the baseline assumptions are "unrealistic with respect to the continued operation of some natural gas-fired generation…"[10] Public Advocates Office, in contrast, argues that the retention of most or all of the current thermal generation fleet in the staff proposed RSP may not be reasonable.[11] SDG&E suggests that while the Commission's

---

9 CalCCA Opening Comments at 40-41.

10 *Comments of Calpine Corporation on Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (Calpine Opening Comments), Dec. 17, 2019, at 2.

11 *Comments of the Public Advocates Office Responding to the Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (Public Advocates Office Opening Comments), Dec. 17, 2019, at 18.

extension of once-through-cooling plant retirement dates was reasonable, "the volumes identified in the final RSP should match the staggered extensions identified in the Procurement Track Decision."[12] The disagreement among commenters about the potential for rapid decarbonization of the energy sector suggests strongly that the Commission should perform the Thermal Retention Study proposed in the February 11, 2019 ruling, especially the low thermal retention sensitivity.[13] As the technical debate continues on the extent to which fossil resources are needed in the transition to a carbon-free electricity supply, the Commission needs metrics to conduct more granular evaluation. Not all fossil resources have equal impacts, having different emissions rates, generation profiles, and community impacts. For this reason, CalCCA proposed in its Opening Comments that Staff employ a criteria pollutant metric in its modeling to examine the impacts of various configurations on climate goals and communities. This metric, presenting criteria pollutant data already collected within SERVM, would help staff and parties better understand the risks associated with retained gas with low capacity factors.[14]

The staff should hold an additional workshop to examine the feasibility of adopting this metric, and solicit feedback on how LSEs should incorporate such metric in their IRPs. The models track criteria pollutant output, and presenting the information would give parties a better understanding of differences between alternative plans. Topics to consider in the workshop could include potential local or regional aggregations of resource criteria pollutant levels to identify geographical differences in output for alternative plans.

---

[12] SDG&E Opening Comments at 6.

[13] Rulemaking (R.) 16-02-007 *Administrative Law Judge's Ruling Seeking Comment on Proposed Scenarios for 2019-2020 Reference System Portfolio*, Feb. 11, 2019.

[14] CalCCA Opening Comments at 16.

D. Evaluate SCE's Alternative Scenarios to Ensure California Aims to Meet Its Climate Goals

SCE's Opening Comments place doubt on the ability of the 46 MMT RSP to enable the state to achieve its climate goals, proposing instead adoption of its 38 MMT scenario.[15] CalCCA fully supports ensuring the use of a GHG emissions scenario that will ensure achievement of these critical goals, but adoption of SCE's scenario at this point is premature. Accordingly, SCE's proposal should be reviewed in the January workshop proposed in Section F, examining at a minimum the observations offered below.

1. Procurement in Response to D.19-11-016

SCE's methodology -- optimal resource buildout and costs for the 38 MMT portfolio -- differs starkly from the Staff's portfolios. SCE includes in the baseline set of resources the 3,300 MW of procurement required by Decision (D.) 19-11-016, thereby excluding this procurement and related costs from the results reported for the optimal buildout.[16] As a result, the incremental capacity addition comparison included in Figure 8 of SCE's comments is misleading: to accurately compare SCE's result to the RSP, the overall buildout of storage in the 38 MMT portfolio should be 9,720 MW, and not 6,420 MW as SCE's methodology presents. By understating the required buildout, SCE also understates costs; the lower end of the resource cost accordingly under SCE's 38 MMT portfolio should be $3.1 billion (using the incremental cost of $0.5B for 3,300 MW of 4-hour storage assumed by SCE). In other words, SCE's 38 MMT portfolio costs are about $600 million per year higher than Staff's 46MMT Alternate portfolio and $600 million lower than Staff's 38MMT portfolio. While these costs may be justified as

---

15 *Southern California Edison Company's (U 338-E) Opening Comments on Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (SCE Opening Comments), Dec. 17, 2019, at 23.

16 *Id.* at 26.

necessary for achieving state climate goals, an examination of the differences between the portfolios, their costs, and their ability to meet the State's GHG and disadvantaged community impacts goals is needed.

2. Import Limitations

SCE includes consistent and potentially more realistic import limits for the PRM constraint and the import limit during peak conditions; SCE recommends using 5,000 MW plus the contribution of three out-of-state units (Hoover, Palo Verde, and Intermountain for a total of 1,937 MW in 2020).[17] SCE's approach appears to be consistent with CalCCA's contention that 5,000 MW of import RA and energy assumption is highly restrictive, but fails to recognize that there are other import resources for which CAISO LSEs have rights to the imported power (*e.g.,* Central Valley Project output), suggesting a higher import limit may be warranted.

In addition, SCE[18] and other stakeholders (*e.g.,* CAISO,[19] AWEA[20]) have identified a need to make consistent assumptions in RESOLVE and SERVM that fixes the imports to the same level in both models. While the approach used by Staff is internally consistent in this manner, the consistency takes a step too far in assuming that the restriction applies equally to RA and energy. Even assuming a limitation during peak hours on RA imports, analysis presented by the CAISO demonstrates that significantly higher energy imports are available during non-peak hours. Consequently, restricting RESOLVE to 5,000 MW for all 37 representative days is overly conservative, including for many days/scenarios that do not represent the peak load hours for

---

17 *Id*. at 25.

18 *Id*. at 25-26

19 *Comments of the California Independent System Operator Corporation* (CAISO Opening Comments), Dec. 17, 2019, at 12.

20 *Comments of the American Wind Energy Association California Caucus on the Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (AWEA Opening Comments), Dec. 17, 2019, at 5.

which some parties assert import restrictions. As CalCCA noted in its Opening Comments,[21] there is no need to artificially restrict SERVM (to even 6,927 MW as recommended by SCE) imports if the Commission has confidence in the WECC-wide unit commitment and dispatch modeled in SERVM.

3. Wind Resource Penetration

SCE's 38 MMT portfolio has higher wind resources (primarily OOS) than Staff's 46 MMT Alternate portfolio.[22] CalCCA could support this outcome provided that the portfolio properly accounts for the cost of transmission triggered by the OOS wind resources. It is unclear from SCE's Opening Comments exactly how these costs were addressed. Furthermore, the portfolio must account for transmission interconnection and integration costs. Finally, the availability of these resources will also turn on the availability of transmission rights. To the extent that the allocation of import capacity is only done on a short term basis and does not reflect the needs for transmission rights, these resources may not be optimally available. Accounting for these costs and constraints is critical to ensure a reference portfolio that accurately embodies the fundamental principle of cost causation.

4. Stress Testing for Reliability

SCE used ABB's capacity expansion model to develop the portfolios[23] and then tested it using the PLEXOS production cost model.[24] It does not appear, however, that SCE used a stochastic production cost model to verify that the portfolios produced a 0.1 LOLE. SCE's 38 MMT portfolio should be tested in SERVM to ensure that it meets the reliability threshold.

---

[21] CalCCA Opening Comments at 17.
[22] *See, e.g.,* SCE Opening Comments at 32, Figure 8.
[23] *Id*. at 49.
[24] *Id*. at 50.

E. Reexamine the Declining Battery Storage ELCC Curve

Staff's analysis assumes a declining ELCC for battery storage as penetration increases for two reasons. First, storage is assumed to flatten the net peak, requiring longer duration and/or higher stored energy volumes to continue to be able to offset a shifting peak load hour. Second, increasing penetrations face the challenge of having enough energy available for sufficient charging to support peak demand. Parties' Opening Comments question this approach.

SCE opposes the adoption of this substantial change in the capacity value of battery storage so late in the IRP process, particularly without significant vetting of the analysis used to justify this change. In particular, SCE points out that "[t]here is no explanation how this proposed change impacts longer-duration storage (i.e., > 4 hours) in the RESOLVE model."[25] UCS likewise challenges Staff's approach, suggesting that with a lower GHG target, higher renewable capacity would undoubtedly alter the battery storage ELCC curve, increasing battery storage ELCC values.[26] CESA proposes additional review, recommending that "the Commission evaluate the benefits of diversifying the state's energy storage portfolio by incentivizing the development of technologies with durations over eight hours."[27]

CalCCA agrees with SCE that this is a material change that has not been sufficiently vetted to ensure its accuracy. Moreover, given the increasing role for battery storage as the state approaches its climate goals, making unnecessarily conservative or erroneous assumptions regarding the future value of storage carries the potential to significantly distort results. In

---

25 *Id*. at 12.

26 *Opening Comments of the Union of Concerned Scientists on the Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (UCS Opening Comments), Dec. 17, 2019, at 3.

27 *Comments of the California Energy Storage Alliance on the Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (CESA Opening Comments), Dec. 17, 2019, at 7.

particular, Staff's assumption does not recognize that as the net peak is reduced and moved by the deployment of storage, storage capacity should be able to alter dispatch to more effectively address the new peak as needed. CalCCA thus proposes that Staff undertake more scenario analysis, involving greater penetration of solar generation (*i.e.,* availability for battery storage charging and longer duration storage) before modifying RA counting criteria for battery storage.

F. Schedule a Two-Day Workshop for Late January

With additional time provided in an extended schedule, the Commission will have the opportunity to explore issues that are pivotal to the success of this IRP cycle. CalCCA recommends that the workshops address, at a minimum, the following topics:

- The ability of Staff's 46 MMT and SCE's 38 MMT scenarios to meet climate goals;
- Development of more reasonable import assumptions;
- The need for Staff's proposed 2,000 MW of generic effective capacity;
- Development of appropriate criteria pollutant metrics;
- Differing viewpoints on battery storage curves; and
- Staff's aggregation process, including issues related to problems encountered in the previous IRP cycle.

III. CONCLUSION

For all of the foregoing reasons, CalCCA respectfully requests consideration of the recommendations identified in CalCCA's Opening and Reply Comments and looks forward to an ongoing dialogue with the Commission and stakeholders.

January 6, 2020

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
Counsel to the California Community Choice Association

APPENDIX A

Illustrative Timeline for CCA IRP Development and Required External Inputs

The table below provides an illustrative timeline based on the timeline for the development of the joint CCA IRP effort assuming the release of load inputs on January 22, 2019 and a Reference System Portfolio adoption date of March 26, 2020, as indicated in ALJ Fitch's November 19, 2019 email to the IRP Service List. Assuming this timeline, LSEs could feasibly complete and submit their IRP submissions by July 31, 2020 for an August 1, 2020 submission. Such an extension would allow the Commission 30 weeks to compile and evaluate IRPs and adopt and submit a Preferred System Portfolio, relative to the 38 weeks required in the 2017-2018 IRP cycle.

Activity	Weeks Req'd	Completion Date	Dependencies
Modeling Inputs: Compile and develop inputs, assumptions, CCA load and portfolio data, including CCA program load modifiers (*e.g.*, more aggressive EV and BTM adoption from CCA programs)	4	2/14/2020	IEPR Load Forecasts
Portfolio Development: Develop conforming (CPUC and local requirements) and preferred portfolios (*e.g.*, aggressive decarbonization portfolio)	3	3/6/2020	IRP Templates (*e.g.*, Clean System Power)
Initial Portfolio Testing: Perform Production Cost Modeling on portfolios and test against RSP	3	3/27/2020	Adopted Reference System Portfolio
Initial Stakeholder Outreach: Conduct stakeholder meetings on initial portfolios	3	4/17/2020	All Above
Advanced Portfolio Testing: Perform sensitivity analysis and stochastic testing on preferred portfolio(s) for reliability, economic performance	3	5/8/2020	All Above
Disaggregate: Disaggregate and allocate portfolios across participating CCAs	2	5/22/2020	All Above
Portfolio Selection: Select preferred portfolio through board and stakeholder engagement	3	6/12/2020	All Above
IRP Drafting: Draft IRP submissions, narratives, fill templates	3	7/3/2020	All Above
IRP Board Approval: Notice IRP results and hearings for board approval by each CCA; IRP submission to CPUC	4	7/31/2020	All Above

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

JOINT MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY TO AMEND SCOPING MEMO

JANET S. COMBS
RUSSELL ARCHER
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, CA 91770
626.302.1524
Janet.Combs@sce.com

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

Evelyn Kahl
Ann C. Springgate
Buchalter, A Professional Corporation
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
ekahl@buchalter.com

Counsel to CALIFORNIA COMMUNITY CHOICE ASSOCIATION

GOODIN, MACBRIDE,
SQUERI & DAY, LLP
Michael B. Day
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
Email: mday@goodinmacbride.com

Attorneys for COMMERCIAL ENERGY OF CALIFORNIA

January 3, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

JOINT MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY TO AMEND SCOPING MEMO

Pursuant to Rule 11.6 of the Rules of Practice and Procedure of the California Public Utilities Commission ("CPUC" or "Commission"), Southern California Edison Company ("SCE"), the California Community Choice Association ("CalCCA"), and Commercial Energy ("Commercial") respectfully make this Joint Motion for Additional Comment Opportunity and to Extend Time to Request Evidentiary Hearings Related to Working Group Three Final Report ("Joint Motion").[1]

Pursuant to Section 3.2 of the February 1, 2019 Phase 2 Scoping Memo and Ruling of Assigned Commissioner in this proceeding ("Scoping Memo"), January 30, 2020 is the deadline for the Working Group Three Final Report to be filed and served ("Final Report"). Subsequent to the filing and service of the Final Report, the Scoping Memo provides parties an opportunity to request motions requesting evidentiary hearings by the tenth working day after filing and service of the Final Report.

[1] Pursuant to Rule 1.8(d), counsel for SCE confirms that counsel for CalCCA and for Commercial have authorized SCE to file this Joint Motion on their behalf.

SCE, CalCCA and Commercial are Co-Chairs of Working Group Three. On December 26, 2019, the Co-Chairs emailed parties concerning the procedural schedule applicable to the Final Report and requested that parties provide feedback on the Co-Chairs' proposed modifications to the procedural schedule to accommodate additional comment opportunities. To fully develop the record concerning the matters described within the Final Report, the Co-Chairs proposed to amend the procedural schedule to provide for party comments and reply comments on the Final Report, and modify the deadline pertaining to motions requesting evidentiary hearings to following the filing and service of reply comments. Specifically, the Co-Chairs proposed the following additions and changes to the remaining procedural schedule, shown in **bold** below, which parties either supported or did not oppose:

R. 17-06-026, Remaining Phase 2 Schedule for Working Group Three Portfolio Optimization and Cost Reduction and Allocation and Auction

Event	**Date**
Working Group reports on consensus and non-consensus items filed and served at Commission (Final Report)	1/30/2020
Opening Comments on Working Group Three Final Report	**2/13/2020**
Reply Comments on Working Group Three Final Report	**2/20/2020**
Motions requesting Evidentiary Hearings	**2/27/2020**
Proposed Decision(s) Issued	Q2 2020
Commission Voting Meeting	30 days after PD

The Co-Chairs respectfully request that the Administrative Law Judge (ALJ) to this proceeding grant the Co-Chairs amendments to the scoping memo to provide for additional commenting opportunities, and to extend the deadline for motions requesting evidentiary hearings. The Co-Chairs support such amendments to facilitate full record development to enable the Commission to reach a reasoned decision on those matters presented in the Final Report.

The Co-Chairs further request that, pursuant to Rule 11.1 (e), the ALJ reduce the time period to reply to this Joint Motion to four days. The Co-Chairs file this Joint Motion following parties' responses to SCE's December 26, 2019 email. Comments were received in support of the Joint Motion and no party expressed opposition.[2]

For the foregoing reasons, the Co-Chairs respectfully request the ALJ grant the Joint Motion and amend the Scoping Memo to adopt a modified procedural schedule as requested herein.

Respectfully submitted,
JANET S. COMBS
RUSSELL ARCHER

/s/ Janet S. Combs
By: Janet S. Combs

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue Post Office Box 800
Rosemead, California 91770
Telephone: 626.302.6522
E-mail: Janet.Combs@sce.com

On behalf of Commercial Energy, California Community Choice Association, and Southern California Edison Company

January 3, 2020

[2] *See* CPUC Rules of Practice and Procedure, §11.6, Motion for Extension of Time ("… If other parties to the proceeding are affected by the extension, the party requesting the extension must first make a good faith effort to ask such parties to agree to the extension. The party requesting the extension must report the results of this effort when it makes its request….").

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

POST-WORKSHOP COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Irene K. Moosen
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
415.587.7343
regulatory@cal-cca.org

Director, Regulatory Affairs
California Community Choice Association

Kevin Fox, Partner
Sheridan Pauker, Partner
Keyes & Fox LLP
580 California St., 12th Floor
San Francisco, CA 94104
510.314.8200
kfox@keyesfox.com

Counsel to the California
Community Choice Association

January 21, 2020

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

POST-WORKSHOP COMMENTS OF
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

I. Summary of CalCCA Position on DA Expansion.

CalCCA is the statewide organization of Community Choice Aggregators ("CCAs").[1] California's 19 operational CCAs served an annual load of approximately 44,400 GWh in 2019, or about one quarter of the load served within the service territories of California's three largest investor-owned utilities ("IOUs").[2] As of September 2019, CalCCA members have entered into a collective 3,400 MW of agreements for new renewable generation, energy capacity, and battery storage facilities in furtherance of California's leading and vital climate, air pollution and reliability goals.[3] CalCCA appreciates this opportunity to submit post-workshop comments on the Energy Division's January 8, 2020 workshop ("January 8 Workshop"). That workshop solicited input on an Energy Division study that will inform the Commission's recommendations to the

---

1 CalCCA's members include: Apple Valley Choice Energy, Clean Power Alliance of Southern California, Clean Power San Francisco, Desert Community Energy, East Bay Community Energy, King City Community Power, Lancaster Choice Energy, Marin Clean Energy, Monterrey Bay Community Power, Peninsula Clean Energy Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, Solana Energy Alliance, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy Alliance.

2 *See* California Energy Commission, Load-Serving Entity and Balancing Authority Forecasts, Form 1.1c, submitted Feb. 5, 2019, available at: https://ww2.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_LSE-BAF.php.

3 A full list of CCA contracts is attached as Appendix A.

Legislature regarding further direct access ("DA") expansion. CalCCA was an active participant in that workshop, with CalCCA representatives appearing on each of the workshop panels.

SB 237 recognizes the importance of doing no harm to ongoing climate, environmental, reliability, and cost-equity initiatives by requiring that any recommendations concerning expansion of DA satisfy the following criteria:

(1) the recommendations are consistent with the state's greenhouse gas ("GHG") emissions reduction goals;

(2) the recommendations do not increase criteria air pollutants and toxic air contaminants;

(3) the recommendations ensure electric system reliability; and

(4) the recommendations do not cause any undue cost shifting between bundled and DA customers.

As discussed at the January 8 Workshop, and in these comments, DA expansion now will almost certainly harm the state's ability to meet its GHG goals, will increase criteria air pollutants/toxic air contaminants, will undermine system reliability, and will result in undue cost shifts to bundled and CCA customers from commercial and industrial customers taking DA.

As highlighted in the work that the Commission's Policy and Planning Division ("PPD") performed in the Customer Choice Project,[4] and as experience in California and in other states highlights further, retail choice entails numerous structural issues for policymakers seeking to achieve environmental and reliability goals. Moreover, California's policy regime is undergoing a significant transition as the state moves to Integrated Resources Planning ("IRP") – encompassing numerous load serving entities rather than primarily focusing on the three large IOUs – and significant potential changes to the resource adequacy ("RA") market, including discussion of a central buyer for RA resources. PG&E's bankruptcy further exacerbates

[4] *See* https://www.cpuc.ca.gov/customerchoice/

uncertainty during this transition period. All of this must be factored into any recommendations on DA expansion, as too must consumer protection concerns.

In light of these concerns, the best recommendation – indeed, the *only* recommendation, given the paucity of the record here – the Commission can make to the Legislature now is to defer expansion of DA until appropriate mechanisms are in place to ensure California's continued climate leadership. Without a deferral to ensure these issues are sorted out, California's electricity market will most likely rapidly backslide on progress being made in emission reductions, reliability markets, and consumer protections.

II. DA Expansion Cannot Currently Be Squared with SB 237's Mandates.

SB 237 poses questions about Energy Service Providers ("ESPs") collectively, not about any one ESP. We recognize, as discussed by CalCCA representatives at the workshop, that there is significant diversity among ESPs serving California's nonresidential DA customers. Some ESPs and their customers are reducing GHG emissions from the electric sector ahead of legal requirements and contracting for development of new renewable resources. However, most are not. These comments address the issues associated with the collective practices of ESPs and the considerations the Commission must undertake associated with broader potential load migration to DA. They are not intended to describe any particular ESP or ESP practice, unless specifically noted.

Several workshop participants pointed to the existence of retail competition in other states to support assertions that DA can and should be expanded in California. CalCCA encourages Energy Division Staff to look very closely at challenges created by ESPs in other states with retail choice. For example, just this past December, New York enacted "significant reforms to the retail energy market" after a three-year investigation revealed many troubling ESP practices in the small commercial and residential retail markets. According to the New York Public Service Commission:[5]

> The record establishes that many of the concerns raised by the non-ESCO parties about the current operation of the retail access market are warranted. The Commission shares those concerns, particularly regarding the lack of easily accessible and comprehensible product and pricing information and, the number of complaints alleging that bad-acting ESCOs[6] were misleading and exploiting customers. Thus, we conclude that significant changes to provisions governing retail access are needed to provide adequate protections for New York customers. **If market participants are unwilling, or unable, to provide material benefits to customers beyond those provided by utilities in exchange for a regulated, just and reasonable rate, the market serves no proper purpose and should be ended.**

The major takeaway from California's and other states' experiences is that expanding customer-specific retail competition presents structural challenges to, among other things, development of new renewable resources. To square customer-specific retail competition under short-term contracts with achieving environmental and reliability goals, other states have adopted market and regulatory structures that are materially different from California. In particular, other states have market features that California does not (e.g., centralized capacity markets and a central long-term buyer for RECs in New York; an energy-only market in Texas). These states have taken different approaches than California in evolving their retail markets, and they have faced and addressed issues with which California is only now coming to grips. Notably, however, while these states' market features may mitigate some of the more challenging structural issues associated with retail choice, these states are *still* having problems with retail choice.

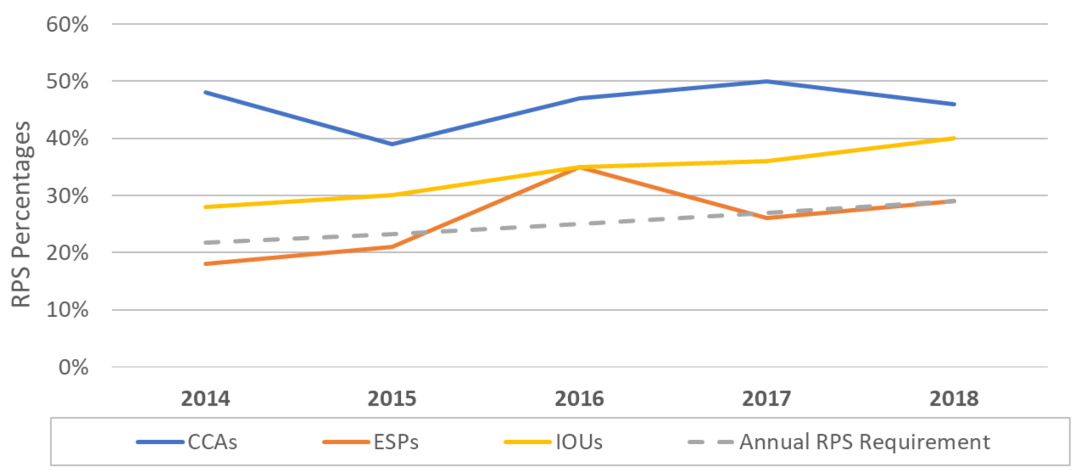
---

5 State of New York Public Service Commission, *Order Adopting Changes to the Retail Access Energy Market and Establishing Further Process*, Case nos. 15-M-0127, 12-M-0476, and 98-M-1343 (December 12, 2019) ("NYPSC Order") at 12 (emphasis added). Available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-M-0127&submit=Search

6 ESCOs are energy service companies that are akin to energy service providers in California.

During the January 8 Workshop, parties repeatedly highlighted the need for market structures to prevent "backsliding"[7] on the State's climate, environmental, reliability, and cost equity goals. CalCCA believes the State will see short-term and long-term forms of environmental backsliding if DA is expanded without any further market changes. In the short-term – incumbent load-serving entities ("LSEs") have been procuring RPS and GHG-free resources beyond minimum requirements. ESPs by and large have not. The following graphic shows the difference in environmental emphasis in historic ESP RPS compliance practices compared to other LSEs.[8]

Figure 1. Average Actual LSE RPS Percentages (2014-2018)



In a reopening scenario, customers will shift from "greener" incumbent LSEs (the blue and yellow, upper, lines) to "browner" ESPs (the lower, orange, line). All else equal, this will increase GHG and criteria pollutant emissions versus a continuation of the status quo. At the workshop, a DA advocate took issue with this contention, asserting that new DA customers might opt for greener products than current DA customers do. However, nothing in the historical record of ESPs

7 By "backsliding", we mean an increase in GHG or criteria pollutant emissions versus a base case where there is no DA expansion and customers continue to be served by their incumbent providers, and or where IOUs continue to be displaced by greener CCAs.

8 *See* California Public Utilities Commission, *2019 California Renewables Portfolio Standard Annual Report, Tables 2, 4 and 6* (Nov 2019).

to date suggests it is likely that customers leaving incumbents for ESPs will *en masse* choose products as green as those of their prior supplier.

Turning to the longer-term impacts of DA expansion on achieving California's GHG-reduction goals, the dots here are more numerous but still easy to connect. Project developers need "financeable" LSEs to sell to in order to get lenders to provide the funds needed for new construction. LSEs, for their part, need assurance of a revenue stream for the duration of any power purchase agreement ("PPA") with a project developer. PPAs for new construction are long duration, generally fifteen years or more, and a developer needs to know its counterparty will be able to stand behind a PPA for that duration of the contract. In an era of declining prices, today's bargain is tomorrow's stranded cost. LSEs are well aware of this phenomenon, and so want such deals only if they are "back-to-back" with their retail sales arrangements. And therein lies the rub. Developers need decade-plus long deals, while in a competitive market environment LSEs would have no assurance of keeping customers for that long, at rates that would cover a PPA's costs. **The mismatch between the duration developers need in a contract for a new project, and the length of time an LSE can be confident of having a given load at a given price is a structural impediment to new project development in any market with retail competition.**

Expanding DA in the absence of market rules that prevent backsliding on the state's policy goals would be extremely detrimental to CCAs, to our contractual counterparties, and to our customers. Under a full DA expansion, CCAs could lose a significant percentage of load. Extreme levels of load instability threaten to undermine the long-term contracts that CCAs have already entered.[9] This brings us to the "death spiral" scenario. Consider an LSE locked into long-term

---

[9] *See*, *e.g.*, D.19-02-022 at 16 ("an LSE who experiences load migration may be potentially stranded with these resources and costs.")

fixed price contracts that consequently ends up with higher prices than competitors. Stuck with high wholesale costs, that LSE raises retail prices. Customers leave. Those expensive contracts' costs now have to be recovered over a smaller customer base. That LSE raises prices further. More customers leave. Eventually not enough customers are left to pay counterparties, and that is the end of that LSE. And likely of the generator(s) on the other side of that LSE's PPA(s). Furthermore, credit markets will take note of this mismatch and finance projects at a higher interest rate, resulting in higher prices and lower affordability. Expanding DA without providing risk limiting options to current non-IOU LSEs will certainly raise the price of power to all customers, as suppliers factor a risk premium into their PPA and other energy-contract prices.

We hasten to add that this is a risk, not a certainty, associated with DA expansion. CCAs are taking and will continue to take steps to avoid it coming to pass. And we add further that the Commission can address this risk in a variety of ways, including an indifference adjustment for all LSEs. But what is certain is that, faced with this scenario, and absent Commission action to mitigate risks, *all* LSEs are going to be less likely to enter contracts, or as many contracts, for new capacity.[10] This is true notwithstanding that, beginning in 2021, 65% of a retail seller's RPS-eligible procurement must come from long-term procurement contracts with delivery terms of 10 years or more.[11] This long-term contracting requirement may have been intended to push CCAs and other LSEs to enter long-term contracts for new development, but what we heard at the January 8 Workshop is that there is a push among ESPs to do financial rather than physical deals, with contractual offramps that effectively defeat the purpose of this requirement.

---

[10] *Id.* at 16 ("The uncertainty around load migration discourages LSEs from procuring too far out given that they do not know if they will have a particular set of customers in the future.")

[11] *See* Pub. Util. Code § 399.13(b).

We cannot emphasize the outcome here strongly enough, and so will say it again. **The mismatch between the duration developers need in a contract for a new project, and the length of time an LSE can be confident of having a given load at a given price is a structural impediment to new project development in any market with retail competition.** PPD recognized this issue in the Commission report titled, *California Customer Choice - An Evaluation of Regulatory Framework Options for an Evolving Electricity Market*, issued August 2018 (the "Green Book"). Key question No. 4 in Table 6 calls the question: "How does the choice model leverage investment necessary to finance the evolution of the electric grid?"[12] Beneath this question lay further questions:

- What entity makes the necessary large capital investments to operate the grid? Upon what authority?
- In what timeframe are investments being made?
- Is there an intentional shift of investment responsibility from the incumbent utility to other parties?
- What investment risks are anticipated and how are they being mitigated?
- What is the model for LSEs other than the IOUs and private entities to raise private capital/secure loans for new build/new generation (e.g. established credit worthiness, viable rate of return)?[13]

PPD raised similar questions yet again in the report titled, *California Customer Choice Project - Choice Action Plan and Gap Analysis*, issued December 2018 (the "Gap Analysis").[14] These questions remain unanswered today. These are but a few of the unanswered questions from the Green Book and the Gap Analysis that are germane to the first SB 237 criteria: that any expansion

---

12 Green Book at 29.

13 *Id.*

14 *See* page 75 ("In the future, it is unclear whether capital investment necessary for new generation to meet the state's 2030 goals and beyond can be financed and, if so, delivered on time if the market evolves from a few larger buyers (IOUs) to many small buyers (CCAs, ESPs, and IOUs).")

must be "consistent with the state's greenhouse gas emissions reduction goals." Until and unless the Commission acts to address these issues, an expansion of DA threatens the new project development pipeline and will increase the cost of new developments as developers include a risk premium to cover this regulatory uncertainty, thus inhibiting achievement of SB 100 goals.

In sum, the Commission should not recommend that the Legislature undertake any further DA reopening until key prerequisites to this significant policy move are resolved. First and foremost, key and complex market structuring questions must be settled and implemented. Where we are going as a state should be addressed in a formal proceeding in concert with Legislative action, and as a result of conscious decision-making. Expansion of DA should not be the result of a rushed six-month process with virtually no record development. The track record of DA in this and other states raises red flags, and certainly does not provide a basis for the Commission to find that a further DA expansion is consistent with California's environmental and reliability policies.

III. Based on the Actions of ESPs to Date, an Expansion of Direct Access Is Inconsistent with California's Greenhouse Gas Emissions Reduction Goals.

SB 237 requires the Commission's recommendation regarding any further DA expansion to be consistent with achieving California's GHG emission reductions goals.[15] To reach a finding on GHG impacts, Section 2.1.1 of the Scoping Memo states that the Commission "will determine whether the recommendations are consistent with its RPS and IRP programs."[16] For the reasons discussed below, ESP's RPS compliance history and proposed future RPS procurement make such a determination impossible.

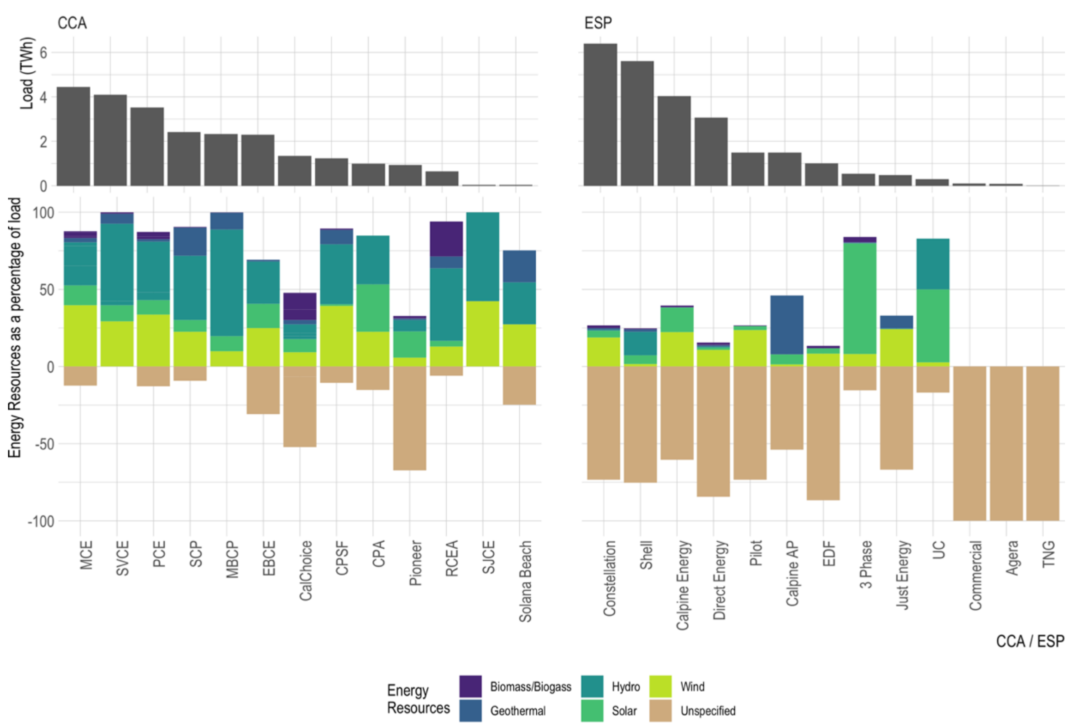
---

[15] Pub. Util. Code § 365.1(f)(2)(A).

[16] Scoping Memo at 5.

First, ESPs procure less RPS-eligible energy as a percentage of retail sales than CCAs and IOUs. Given this, any aggregate shifting of load from IOUs or CCAs to ESPs means more Californians will receive an energy supply with a higher carbon content that undermines the state's GHG goals and increases criteria air pollutants and toxic air contaminants. This is demonstrated in **Figure 2** below, which uses Portfolio Content Label ("PCL") data to show that, while ESPs have taken diverse approaches to RPS compliance, they are much "browner" as a whole than IOUs and CCAs, with the largest ESPs being among the "brownest." The top of Figure 2 below shows the load of each CCA and ESP and the bottom of Figure 2 plots the energy sources of each CCA and ESP as a percentage of total load served.[17]

Figure 2. 2018 Energy Resource Mix for California CCAs and ESPs



CEC

[17] This publicly available data comes from the California Energy Commission's 2018 Power Source Disclosure Program that discloses the historical contracted volumes by fuel type.

The differences in ESP and CCA energy supplies highlighted in Figure 2 lead to very different carbon intensities (and also to very different levels of emissions of criteria air pollutants and toxic air contaminants). For example, using the PCL data from Figure 2 and applying an emissions rate of 0.428 MT CO_2/MWh[18] to unspecified and natural gas-fired sources of generation, ESPs' carbon intensity averaged 0.207 MT CO_2/MWh in 2018 while CCAs' carbon intensity averaged 0.044 MT CO_2/MWh. As a result, each ESP on average emitted 510,103 tons of CO_2 in 2018, while each CCA on average emitted 82,172 tons of CO_2. In fact, even though CCAs serve significantly more load than ESPs, ESPs still emitted a total of 5,101,027 tons of CO_2 in 2018, which is almost five times the amount of CO_2 that CCAs as a whole emitted (1,068,239 tons of CO_2). This data is summarized in **Figure 3** below.

Figure 3. 2018 CO_2 Emissions for California CCAs and ESP

	Carbon Intensity (MT CO_2/MWh)	**Average CO_2 Emissions (Tons)**	**Total CO_2 Emissions (Tons)**
CCAs	0.044	87,172	1,068,239
ESPs	0.207	510,103	5,101,027

As a result of the different carbon intensities of ESP and CCA energy supplies, any load shifting from CCAs to ESPs, all else equal, will increase aggregate GHG emissions in California.

Second, ESPs as a whole have consistently failed to achieve minimum RPS compliance levels in any compliance period to date. Accordingly, any load shifting from CCAs to ESPs, all else equal, will increase the likelihood that California will not achieve its RPS goals. Six ESPs were deemed noncompliant in compliance period ("CP") 1 (2011-2013).[19] Three ESPs were

[18] California Air Resources Board default emissions factor utilized in its Cap-and-Trade Regulation. *See* 17 CCR § 95111(b)(1).

[19] *See* California Public Utilities Commission, *2019 California Renewables Portfolio Standard Annual Report* at 24 (Nov 2019).

deemed noncompliant in CP 2 (2014-2016).[20] Two of these three were found to be non-compliant because they did not meet the long-term contracting requirements.[21] The deficit from these non-compliant ESPs was sufficient to pull ESPs as a whole below the minimum attainment threshold.

Third, ESPs have demonstrated limited commitment to entering long-term contracts to facilitate new RPS project development in California. Although developers need long-term contract commitments to finance new construction, many ESPs' procurement practices are inconsistent with the long-term commitments that developers need. For example, the Commission found in its decision on 2019 RPS procurement plans that ESPs have historically relied on short-term contracts to meet RPS requirements.[22] Consistent with this observation, in the most recent compliance period CP 2 (2014-2016), half of ESPs[23] met existing long-term contracting requirements[24] entirely through long-term agreements for unbundled RECs, not for new construction.[25]

If we look to the report titled *2019 California Renewables Portfolio Standard Annual Report*, we see virtually no plans by ESPs to procure from newly constructed projects.[26] Moreover, as TURN noted at the January 8 Workshop, no LSE has yet complied with the new 65% long-term contracting requirement that becomes effective in 2021. Although the data necessary to fully

---

20 *Id.* at 25.

21 *Id.*

22 *See* D.19-12-042 at 9.

23 7 of 14 ESPs that submitted public RPS Compliance Reports in 2018. Includes data from 2017 for UC Regents and Commercial Energy of California, as 2018 reports for these LSEs were not available on the CPUC's RPS Compliance Report archive at ftp://ftp.cpuc.ca.gov/RPS_PPAs/Compliance%20Report%20Archives/

24 Equal to 0.25% of retail sales in the prior compliance period. See D.12-06-038 at 40.

25 From 2018 RPS Compliance Reports, Unique Inputs Tab. ESPs reporting use of long-term agreements with PCC 3s to meet requirements include 3 Phases Renewables, Agera Energy, Commercial Energy of CA, EDF Industrial Power Services, Just Energy Solutions, Shell Energy North America, and Tiger Natural Gas.

26 *See*, *e.g.*, California Renewables Portfolio Standard Annual Report, November 2019.

understand the level of ESP non-compliance with existing RPS requirements, including long-term contracting, is largely confidential, given what is available, the Commission should be concerned. For example, the Commission found in a recently issued decision regarding 2019 RPS Procurement Plans that:

> …many of the ESP RPS Plans provided minimal information, while some used boilerplate language that lacked adequate detail … [and] … while most ESPs note that they will meet the long-term contracting requirements, few actually explain how they plan to meet the requirement or show that they have executed long-term contracts.[27]

It is illustrative that Commercial Energy's representative explained in detail at the January 8 Workshop that it would be illogical for ESPs to enter into long-term contracts to serve short-term commitments from customers. Commercial Energy's reluctance to enter long-term contracts is illustrative of the broader concerns that competitive markets present for would-be investors in (and would-be purchasers from) new RPS projects.

In response to ESP and large commercial customer perspectives expressed at the January 8 Workshop that the Commission should set the rules and enforce them, TURN raised an important point: the Commission is just now issuing decisions enforcing noncompliance with RPS Compliance Period 2, which covers the period 2014-2016. This extreme lag means that the Commission does not have a rapid means of controlling LSE performance. In light of the urgent reliability concerns expressed in the most recent IRP decision and the urgency of the climate crisis, current enforcement mechanisms are insufficient to support a further DA opening consistent with the required statutory findings.[28]

---

[27] *See* D.19-12-042 at 55.

[28] D.19-04-040 at 150-151.

Because ESPs are procuring more brown power than other LSEs, it would be unreasonable for the Commission to make the finding that a further DA expansion will be consistent with the state's GHG emission reduction goals. Accordingly, the Commission should recommend that DA not be further expanded at this time because the only available data shows that, historically, ESPs have procured less RPS-eligible supply.

IV. Based on Publicly Available Data, it is Clear that Load Migration to Direct Access Will Increase Emissions of Criteria Air Pollutants and Toxic Air Contaminants.

SB 237 requires that any further DA expansion must not increase emissions of criteria air pollutants and toxic air contaminants.[29] To reach a finding on criteria air pollutants and toxic air contaminants, Section 2.1.2 of the Scoping Memo states that the Commission will determine "whether the recommendations are consistent with its IRP program among other issues…".[30]

The same dynamics impacting GHG emissions will also impact criteria pollutant emissions. A shift from "greener" suppliers to "browner" ESPs will, all else equal, increase criteria pollutant emissions. Moreover, consistency with the IRP, by itself, is not sufficient for the Commission to reach the required finding that any further DA expansion must not increase emissions of criteria air pollutants and toxic air contaminants. The required finding in PUC Code 365.1(f)(2)(B) is binary: the Commission's recommendation regarding whether to expand DA *must not increase criteria air pollutants or toxic air contaminants*. There is no qualifier in the statutory language. In contrast, the IRP statutes require the Commission to ensure that LSE IRP Plans will "*minimize* localized air pollutants with early priority to disadvantaged communities."[31] Minimizing localized air pollutants, as the IRP statutes require, is not the same as SB 237's

[29] Pub. Util. Code § 365.1(f)(2)(B).

[30] Scoping Memo, page 6.

[31] Pub. Util. Code § 454.52(a)(1(I) (italics added).

requirement that the Commission's recommendations *must not increase criteria air pollutants or toxic air contaminants*. Simply put, minimizing and not increasing are not the same. Accordingly, consistency with the IRP, by itself, is not sufficient for the Commission to reach the required statutory finding regarding criteria air pollutants and toxic air contaminants.

CalCCA understands that the Commission has access to data on each resource relied upon by each LSE in its IRP filing and can tie data on criteria air pollutant and toxic air contaminant emissions from IRP filings in the ARB's Facility Search Tool.[32] Doing so will shed light on the historic contributions to these emissions by resources on which ESPs rely to serve load. CalCCA recommends that the Energy Division use this approach in determining whether DA expansion could increase criteria air pollutants and toxic air contaminants, rather than relying solely on ESP compliance with IRP requirements.

Based on RPS compliance data discussed in the preceding section, ESPs are procuring more brown power than other LSEs. Because brown power causes more emissions of pollutants, it is highly likely that expanded DA will lead to more emissions of criteria pollutants and toxic air contaminants. Thus, based on the collective record of ESPs, the Commission cannot recommend any further expansion of DA at this time consistent with the required statutory findings that DA expansion must not increase criteria air pollutants or toxic air contaminants.

V. In Light of Recent Decisions and Significant Policy Uncertainty, the Commission Cannot Reasonably Find that Any Scheduled Reopening of Direct Access Would "Ensure" Electrical System Reliability.

SB 237 requires that any further DA expansion must "ensure" electric system reliability.[33] To reach a finding on the impacts of DA expansion to system reliability, Section 2.1.3 of the

---

[32] https://ww3.arb.ca.gov/ei/disclaim.htm

[33] Pub. Util. Code § 365.1(f)(2)(C).

Scoping Memo states that the Commission will "determine whether the recommendations are consistent with its RA and IRP programs and Section 451."[34]

California's RA market is undergoing significant change, transitioning from a fluid RA market to one characterized by tightening supplies and possible market power issues. For example, in the report titled *State of the Resource Adequacy Market – Revised*, which was circulated in R.17-09-020 on January 14, 2020, Energy Division Staff noted that the RA market is "tight," citing System, Local and Flexible RA deficiencies in 2019 and year-ahead deficiencies for 2020.[35] Although this report did cite unused capacity on the system level, it noted that there may be compliance issues for local capacity, especially in light of recent policy changes regarding Net Qualifying Capacity values.

The California capacity markets are in a further state of flux due to the Commission's signaling that it may shift to a central procurement model. The Commission and other state agencies are currently attempting to study and modify the existing RA and IRP processes to ensure that they can ensure reliability, and increased market complexity appears to be the reason for the top-down, prescriptive approach applied in setting the Preferred System Portfolio in the IRP Proceeding. Increased market complexity was also cited by the Commission as a principal reason for the need for central procurement in the RA proceeding.[36] That proceeding is still ongoing and significant uncertainty remains as to the market structure that the Commission will ultimately

---

34 Scoping Memo, page 6.

35 R.17-09-020 Assigned Commissioner's Ruling on Energy Division's Resource Adequacy State of the Market Report, Appendix A at p. 40 ("In 2019, 11 LSEs had year ahead local deficiencies, six had year ahead system deficiencies, and five had year ahead flexible deficiencies, and many of these deficiencies persisted through the year in month ahead filings. **In addition, some LSEs reported being unable to identify available capacity at any price.** … This trend continued in the 2020 year ahead filings, in which, preliminarily, 20 LSEs had year ahead local deficiencies, five had year ahead system deficiencies, and four had year ahead flexible deficiencies.") (bolding added).

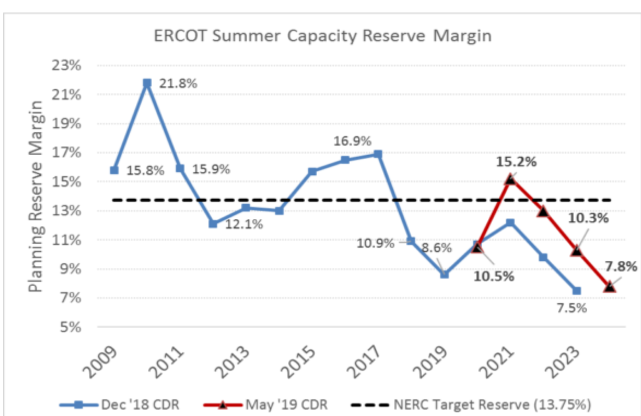
36 R.17-09-020 Energy Division Staff Proposal "Current Trends in California's Resource Adequacy Program Energy Division Working Draft" (February 16, 2018) at 42-52.

adopt. Whether the processes that emerge will ensure reliability in a world of expanded DA and increased load migration cannot be answered until these policies are settled.

The Commission's urgent concern in Decision ("D.") 19-11-016 – which required an additional 3.3 GW of new System RA outside of the normal RA planning cycles – was to address a potential reliability shortfall by 2021 and is implemented over the 2021-2023 cycle. Procurement from D.19-11-016 will likely be the first test of whether existing LSEs can respond to Commission procurement directives aimed at ensuring reliability. The results of this procurement will be an important indication of how well different LSEs will comply with procurement directives to ensure reliability that the Commission determines is needed. ESPs have not been planning for additional load migration, and thus their ability to procure sufficient long-term contracts to supply large amounts of additional load in the near term in compliance with D.19-11-016 is unlikely.

Texas is an object lesson in the risks to reliability that can flow from not having any form of capacity market, centralized procurement, assurances of cost recovery, and/or other guardrails to ensure new construction remains on track. As **Figure 4** shows, new construction in Texas has not kept pace with load growth, and reserve margins have dropped accordingly:

Figure 4. ERCOT's Summer Capacity Reserve Margin: 2019-2023[37]



37 ERCOT, Seasonal Assessment of Resource Adequacy Report (SARA), as reported in a Constellation Energy Blog: https://blogs.constellation.com/energy-management/ercots-preliminary-summer-2019-assessment-a-declining-reserve-margin/

Moreover, this past summer, Texas wholesale spot-market prices spiked to the capped maximum of $9,000/MWh.[38] The Texas view is that this will lead to the construction of needed new capacity. Perhaps that will work. Regardless, this is a real-world example of underinvestment in capacity associated with a "pure" competitive environment, and California does not have the pricing mechanisms that Texas does to even potentially spur new investment.

Given the uncertainty regarding numerous RA issues, not the least of them the central buyer structure and identity, it is currently impossible for the Commission to make clear predictions of the impacts of DA expansion, and thus the Commission cannot recommend further DA reopening at this time consistent with a finding that such reopening will "ensure electric system reliability."

VI. Any Expansion of Direct Access Will Cause Undue Cost Shifting to Bundled Customers.

SB 237 requires that any further DA expansion must not cause undue shifting of costs to bundled service customers of an electrical corporation or to direct transaction customers.[39] To reach a finding on the potential for DA expansion to increase cost shifting, Section 2.1.4 of the Scoping Memo states that the Commission will determine "whether the recommendations are consistent with the PCIA and other mechanisms for ensuring the fair allocation of costs."[40]

Although the PCIA protects bundled customers from cost shifts that may result from IOU load departure, it does not prevent undue costs shifts to CCA customers. PUC Code Section 365.1(c) and other statutes make clear that Commission policies must ensure indifference more

---

[38] https://www.reuters.com/article/us-texas-power-demand/texas-power-prices-briefly-soar-to-9000-mwh-as-heat-wave-bakes-state-idUSKCN1V41HV.

[39] Pub. Util. Code § 365.1(f)(2)(D).

[40] Scoping Memo, page 7.

broadly.[41] Ensuring indifference more broadly is critical to ensuring that *no* customer is harmed by further DA expansion, including CCA customers. Bundled customers are well protected via the PCIA and requirements that all non-IOU LSEs post a bond to cover potential costs associated with a mass return of load to the IOUs. On the other hand, customers served by CCAs do not enjoy those protections and could experience cost shifts as a result of DA expansion.

The Phase 1 decision in this proceeding addressed the ability of LSEs to impose exit fees to prevent undue cost shifting.[42] However, CalCCA requests confirmation from the Commission that current rules are sufficient to allow a CCA to collect an exit fee from departing customers. In particular, the Commission should evaluate Electric Rule No. 23 ("Rule 23") and whether it is currently sufficient to enable a CCA to recover an exit fee implemented by a CCA as a mechanism to protect its customers from cost shifts due to DA expansion.

To further limit cost shift impacts, the Commission should also consider general switching rules applicable to all providers (IOUs, CCAs, ESPs) to ensure that switching is orderly and affords LSEs opportunities to adjust their resource portfolios and procurement plans to accommodate customer migration. Switching rules worth consideration include potential enrollment periods and/or minimum stay obligations. Comprehensive load switching rules applicable to all LSEs are needed to ensure orderly and efficient migration of customers. CCAs are subject to such rules when they form or expand so that the IOUs can adjust their procurement and programs appropriately. Rules must be developed that will allow CCAs and DA providers to plan for load migration before significant additional load migration is allowed to occur.

---

[41] *See*, *e.g.*, Sections 365.2, 366.2(a), 366.3, 380(b), and 454.51(d).

[42] D.19-05-043, page 32 ("We also note that CCAs could consider revising their risk management plans or implementing mechanisms that are similar to the regulatory framework established for the PCIA to further mitigate cost shifting risks.")

In light of the numerous unresolved issues outlined above, the Commission cannot reasonably recommend that the Legislature further expand DA because it cannot find that any such expansion would not cause undue cost shifting.

VII. The Commission Should Not Recommend a Further DA Expansion at this Time Due to Significant Consumer Protection Concerns.

Consumer protection is core to the Commission's responsibilities[43] and was identified as a significant concern in the Customer Choice Project.[44] Although the general assumption is that DA serves large and sophisticated industrial customers, PUC Code section 365.1(f)(2) seeks recommendations concerning expansion of DA to *all* non-residential load – non-residential load ranges from small, relatively unsophisticated energy users ("mom & pop" stores) all the way to companies with robust energy procurement departments. In restructured markets, small non-residential customers face the same consumer protection issues as residential customers.

In the Gap Analysis, the Commission raised concerns over how customers will be treated during a natural disaster if they are unable to pay their bill as a result of an extended Public Safety Power Shutoff event that prevents them from opening for business.[45] More generally, the Gap Analysis raised concerns with ensuring that consumers have high levels of protection during a natural disaster.[46] These issues should be addressed prior to any further expansion of DA. The Gap Analysis also raised concerns regarding slamming and cramming, asking "are rules in place sufficient to prevent slamming and cramming of unsophisticated business customers?"[47] This is a

---

[43] See Pub. Util. Code § 394 *et. seq.*

[44] *See* Green Book at 7-9, 25, 62; Gap Analysis at 22-42.

[45] Gap Analysis at 9, 26, 29.

[46] *Id.* at 20.

[47] *Id.* at 36.

valid concern, as Richard Sedano of the Regulatory Assistance Project highlighted at the 2017 *En Banc* baiting and switching of customers that has taken place in New York.[48]

A more foundational question is whether small commercial customers understand the rate structures and terms of the contract that they are being offered? A recent example from Texas is illustrative, where small customers signed up for retail rates under promises of a low rate (energy savings). When wholesale prices spiked to $6000-9000/MWh, small businesses and residential customers saw their bills skyrocket.[49] Other research points to instances involving ESPs giving incorrect information regarding variable prices, giving incorrect information about contract cancellation, advertising that variable rates would not rise above standard service cost, providing teaser rates on long contracts that reset to much higher rates, charging high cancellation fees, and imposing automatic renewal of contracts.[50] The Commission should ensure that rules are in place to prevent such practices before the Commission can recommend a further DA expansion. Statutory prohibitions are not sufficient and need to be operationalized with clear rules and processes that protect small business customers.

In addition, the Commission must consider whether DA customers will be offered rate structures that are consistent with California's loading order, energy conservation policies, time of use, and other standards. Review of rate offerings in Texas shows many providers offering high

---

48 https://centurylinkconferencing.webex.com/cmp3300/webcomponents/docshow/docshow.do?siteurl=centurylinkconferencing&mactype=Osx&rnd=0.9061442881993139

49 *See*, *e.g.*, https://www.dallasnews.com/news/watchdog/2019/08/23/texans-pay-more-for-electricity-now-than-other-major-markets-a-wholesale-price-record-is-to-blame/

50 See, Competing to Overcharge Consumers: The Competitive Electric Supplier Market in Massachusetts, Jennifer Bosco, National Consumer Law Center, April 2018. Available at: https://www.nclc.org/images/pdf/pr-reports/competitive-energy-supply-report.pdf. *See also* NYPSC Order (noting that adoption of new marketing standards "are the result of a gradual iterative process of increasing the specificity and restrictiveness of the applicable standards to ESCO marketing practices resulting from persistent, unacceptably high numbers of customer complaints alleging ESCO deceptive marketing.")

energy users bill discounts which lower their effective rate.[51] This pricing plan is counter to California's current rate structures and state policies designed to reduce energy use overall to further GHG emissions reduction goals, reduce emissions of criteria pollutants and toxic air contaminants, and as a core means of saving customers money.[52]

Finally, the Commission should consider whether customers will understand the GHG/renewables content of what their EPS is selling? For example, it appears that some ESPs provide zero renewable energy for the first two years of the RPS compliance period and then cover their needs with RECs and other resources in the final year.[53] In this situation, it is reasonable to ask – do current businesses understand that in Years 1 and 2 they are receiving brown system power? Would a small "mom and pop" business understand this situation? While this business model may be "compliant" with Commission rules concerning the RPS program, it is reasonable to conclude that the average small business owner would not understand the nuance of receiving brown system power for two out of three years of their contract. Moreover, depending on the term of the contract between the ESP and the small business, the small business owner could only receive brown power during their term of service with the ESP if it was shorter than the compliance period.

Each of these issues needs to be more fully assessed prior to any further DA expansion to ensure energy consumers are protected from predatory business practices. Until these issues are

---

51 *See*, *e.g.*, https://www.comparepower.com. *See also* https://www.texaspowerguide.com/2017/reliant-high-use-plan/

52 *See* D.15-07-001 at 9-14.

53 For example, this is demonstrated on Figure 1 on page 7 of these post-workshop comments. Figure 1 shows ESPs procuring RPS-eligible energy below the annual RPS requirement for the first two years of CP 2 and then attempting to make up for the shortfall in the last year of the compliance period. *See also* RPS compliance reports of Commercial Energy.

resolved, it would be premature for the Commission to recommend that the Legislature further expand DA at this time.

VIII. Conclusion.

The Commission should recommend to the Legislature that DA transactions should not be further reopened at this point in time because the Commission cannot reasonably recommend *any* further DA expansion consistent with the findings it must make in PUC Code §365.1(f)(2), i.e. that any such expansion would (1) be consistent with California's GHG emission reductions goals, (2) not increase emissions of criteria air pollutants and toxic air contaminants, (3) ensure electrical system reliability and (4) not cause undue shifting of costs. Moreover, as outlined above, there are significant consumer protection issues that must be addressed and be capable of being mitigated before the Commission can recommend any further DA expansion. Accordingly, the Commission should recommend do further expansion of DA load at this time until the many significant issues above are resolved and the Commission has had a period of years to evaluate implementation and compliance with these policies.

Once the issues noted above are sufficiently addressed, in moving forward with any prospective DA reopening, the Commission and/or Legislature would do well to examine limited approaches that *could* allow further short-term retail competition without going backwards on emissions, and without freezing the project development pipeline. One possible approach could be to limit any prospective DA expansion to corporate PPAs "sleeved" through ESPs for <u>new 100% RPS projects</u>. The legislature is already exploring rules around such transactions in SB 702, so examining them first would be in step with legislative activity. There may be other "no regrets" steps that could be front-loaded; TURN made an off-the cuff proposal at the workshop, and we would be interested in learning more about such ideas if and when the Commission moves forward.

January 21, 2020

Respectfully submitted,

/s/ Kevin Fox

Kevin Fox
Counsel to the California Community Choice Association

APPENDICES

Appendix A: List of Contracts Executed by Community Choice Aggregators (CCAs)

CCAs New Renewable PPAs (current to 10-28-2019)								
CCA	Project Name	Technology	Nameplate Capacity (MW)	Nameplate Battery (MW)	Storage Capacity (MWh)	County	PPA Term (Years)	Year
Apple Valley Choice Energy	Mountain View III Wind Farm	Wind	5.0			Riverside	10	2021
Clean Power Alliance	Clearway/Golden Fields	Solar	40.0			Kern	15	2021
Clean Power Alliance	Nextera/Arlington	Solar	233.0			Riverside	15	2021
Clean Power Alliance	Nextera	Wind	300.0			Arizona	15	2020
Clean Power Alliance	Voyager Wind II Phase 4	Wind	21.6			Kern	15	2019
CleanPowerSF	Blythe Solar	Solar	62.0			Riverside	20	2020
CleanPowerSF	San Pablo Raceway	Solar	100.0			Los Angeles	22	2019
CleanPowerSF	Voyager IV	Wind	110.0			Kern	15	2020
CleanPowerSF	Maverick Solar 6	Solar	100.0			Riverside	20	2021
East Bay Community Energy	sPower	Solar + Storage	125.0	80.0	160	Kern	20	2022
East Bay Community Energy	Edwards Solar Project	Solar	100.0			Kern	15	2022
East Bay Community Energy	esVolta Oakland Clean Energy Initiative	Storage	7.0	7.0	28	Alameda	13	2021
East Bay Community Energy	Oakland Energy Storage 1	Storage	20.0	20.0	80	Alameda	10	2022
East Bay Community Energy	Sunrun Oakland Clean Energy Initiative	Storage	0.5	0.5	2	Alameda	10	2021
East Bay Community Energy	Luciana	Solar	56.0			Tulare	15	2021
East Bay Community Energy	Sonrisa Solar	Solar + Storage	100.0	30.0	120	Fresno	20	2022
East Bay Community Energy	Rosamond Solar Project	Solar	112.0			Kern	15	2021

East Bay Community Energy	Salka Wind	Wind	57.5			Alameda	20	2020
Lancaster Choice Energy	Western Antelope Dry Ranch	Solar	10.0			Los Angeles	20	2016
Lancaster Choice Energy	Montain View III Wind Farm	Wind	11.0			Riverside	10	2021
MCE	Hay Road Landfill	Biogas	1.6			Solano	20	2013
MCE	Ostrom Road Landfill	Biogas	1.6			Yuba	18	2013
MCE	Redwood Landfill	Biogas	3.5			Marin	20	2017
MCE	Lincoln Landfill	Biogas	4.8			Placer	20	2013
MCE	Small World Trading	Solar	0.1			Marin	20	2018
MCE	DRES Quarry	Solar	0.1			Marin	20	2017
MCE	Rawson Blum & Leon / Cost Plus Plaza	Solar	0.3			Marin	20	2016
MCE	San Rafael Airport II	Solar	1.0			Marin	20	2012
MCE	Oakley RV and Boat Storage	Solar	1.0			Contra Costa	20	2018
MCE	San Rafael Airport	Solar	1.0			Marin	20	2012
MCE	North Shore / Freethy 1	Solar	1.0			Contra Costa	20	2016
MCE	North Shore / Freethy 2	Solar	1.0			Contra Costa	20	2016
MCE	Silveira Ranch A	Solar	1.0			Marin	20	2019
MCE	Silveira Ranch B	Solar	1.0			Marin	20	2019
MCE	Silveira Ranch C	Solar	1.0			Marin	20	2019
MCE	American Canyon A	Solar	1.0			Napa	20	2019
MCE	American Canyon B	Solar	1.0			Napa	20	2019
MCE	American Canyon C	Solar	1.0			Napa	20	2019
MCE	Soscol Ferry Solar 2	Solar	1.0			Napa	20	2019
MCE	Soscol Ferry Solar 3	Solar	1.0			Napa	20	2019
MCE	Central Marin Sanitation Agency	Solar	1.0			Marin	10	2019
MCE	Dominion / Buck Institute	Solar	1.0			Marin	25	2016
MCE	Solar One	Solar	10.5			Contra Costa	20	2017

MCE	Little Bear 3	Solar	20.0			Fresno	20	2020
MCE	Cottonwood	Solar	23.0			Kings	25	2015
MCE	Mustang 4	Solar	30.0			Kings	15	2016
MCE	Little Bear 1	Solar	40.0			Fresno	20	2020
MCE	Little Bear 4	Solar	50.0			Fresno	20	2020
MCE	Little Bear 5	Solar	50.0			Fresno	20	2020
MCE	Desert Harvest	Solar	80.0			Riverside	20	2020
MCE	Great Valley 1	Solar	100.0			Fresno	15	2018
MCE	Antelope Expansion 2	Solar	105.0			Los Angeles	20	2018
MCE	Voyager II	Wind	42.0			Kern	12	2018
MCE	Strauss Wind	Wind	98.8			Santa Barbara	15	2020
MCE	Cooley Quarry 1	Solar	1.0			Marin	20	2017
Monterey Bay Community Power	BigBeau	Solar + Storage	58.0	18.0	72	Kern	20	2021
Monterey Bay Community Power	RE Slate	Solar + Storage	67.5	20.3	81	Kings	15	2021
Monterey Bay Community Power	Duran Mesa Wind	Wind	90.0			New Mexico	15	2020
Monterey Bay Community Power	Casa Diablo IV	Geothermal	7.0			Mono	10	2021
Peninsula Clean Energy	Mustang II Whirlaway	Solar	100.0			Kings	15	2020
Peninsula Clean Energy	Wright Solar Park	Solar	200.0			Merced	25	2019
Rancho Mirage Energy Authority	Montain View III Wind Farm	Wind	6.0			Riverside	10	2021
Redwood Coast Energy Authority	California Redwood Coast-Humboldt County Airport Microgrid	Solar + Storage	2.0	2.0	8	Humboldt	25	2020
San José Clean Energy	Sonrisa	Solar + Storage	100.0	10.0	40	Fresno	20	2022
Silicon Valley Clean Energy	BigBeau	Solar + Storage	70.0	22.0	88	Kern	20	2021
Silicon Valley Clean Energy	RE Slate	Solar + Storage	82.5	24.7	99	Kings	15	2021

Silicon Valley Clean Energy	Duran Mesa Wind	Wind	110.0			New Mexico	15	2020
Silicon Valley Clean Energy	Casa Diablo IV	Geothermal	7.0			Mono	10	2021
Sonoma Clean Power	Lavio Solar	Solar	1.0			Sonoma	20	2018
Sonoma Clean Power	Stage Gulch Solar	Solar	1.0			Sonoma	20	2018
Sonoma Clean Power	Cloverdale Solar Center	Solar	1.0			Sonoma	20	2019
Sonoma Clean Power	IP Malbec	Solar	1.0			Mendocino	20	2019
Sonoma Clean Power	Bodega Energy West	Solar	1.0			Sonoma	20	2019
Sonoma Clean Power	Petaluma Energy East	Solar	1.0			Sonoma	20	2019
Sonoma Clean Power	RE Mustang	Solar	30.0			Kings	20	2016
Sonoma Clean Power	RE Mustang 3	Solar	40.0			Kings	20	2016
Sonoma Clean Power	Proxima	Solar + Storage	50.0	5.0	10	Stanislaus	20	2023
Sonoma Clean Power	Golden Hills North	Wind	46.0			Alameda	20	2017
Sonoma Clean Power	Sand Hill C	Wind	80.0			Alameda	20	2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

POST-WORKSHOP REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Irene K. Moosen
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
415.587.7343
regulatory@cal-cca.org

Director, Regulatory Affairs
California Community Choice Association

Kevin Fox, Partner
Sheridan Pauker, Partner
Keyes & Fox LLP
580 California St., 12th Floor
San Francisco, CA 94104
510.314.8200
kfox@keyesfox.com

Counsel to the California
Community Choice Association

January 27, 2020

TABLE OF CONTENTS

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

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

**POST-WORKSHOP REPLY COMMENTS OF
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

California Community Choice Association ("CalCCA") appreciates the opportunity the Energy Division has provided to submit these post-workshop reply comments on the Energy Division's January 8, 2020 workshop ("January 8 Workshop").

As discussed below, Energy Service Provider ("ESP") assertions that Senate Bill ("SB") 237 *requires* the Commission to recommend further reopening of direct access ("DA") transactions are incorrect. The Commission's recommendation must satisfy SB 237's statutory criteria requiring no harm to California's environmental, reliability and cost fairness goals. Unless a reopening schedule can satisfy those criteria, the Commission cannot recommend any schedule.

The historic track record and stated plans of ESPs, and the lessons from California's and sister state's electricity markets (highlighted by a recent New York Public Service Commission ("PSC") order)[1] all compel one conclusion: the only reasonable recommendation the Commission can make is to not further reopen DA at this time.

---

[1] State of New York Public Service Commission, *Order Adopting Changes to the Retail Access Energy Market and Establishing Further Process*, Case nos. 15-M-0127, 12-M-0476, and 98-M-1343 (December 12, 2019) ("NYPSC Order") at 12 (emphasis added), *available at*: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-M-

I. SB 237 Does Not Require the Commission to Recommend Any Reopening of Direct Transactions.

In opening comments, the Alliance for Retail Energy Markets ("AReM"), Direct Access Consumer Coalition ("DACC") and the Energy Producers and Users Coalition ("EPUC") asserted that the Commission is bound by SB 237 to recommend a further reopening of DA transactions, beyond the 4,000 gigawatt-hours ("GWh") ordered in Phase 1. This is incorrect. PUC Code §§ 365.1(f)(1) and (2)[2] provide:

> (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.

The recommendations the Commission must make are "*on implementing*" a further direct transactions reopening schedule. A recommendation to not implement a further direct transaction reopening schedule is consistent with this language. The Legislature did not, in

0127&submit=Search; *see also* NYPSC "PSC Enacts Significant Reforms to the Retail Energy Market" (December 12, 2019) ("NYPSC Press Release").

[2] (Emphasis added). We note that SB 237 contained a clerical error in which it repeated §365.1(e), rather than labeling this language as §365.1(f). This is corrected in the published version of the Public Utilities Code.

contrast to the explicit directions found in §365.1(e)(1), *require* the Commission to issue an order that increases the maximum total kilowatt-hour annual limit for such transactions.[3]

Several ESPs in opening post-workshop comments note that §365.1(f)(1) requires *among the possible recommendations the Commission could make* that "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." This recommendation is simply among those the Commission would need to make if the Commission recommends reopening in the first place, not evidence that the Legislature was foreclosing that threshold question.

We agree with The Utility Reform Network's ("TURN") discussion of this issue on page 1 of its opening comments on Administrative Law Judge Christine Powell's September 20, 2019 Ruling (the "September 2019 Ruling"):

> The Commission is obligated to make recommendations relating to additional reopening based upon the extent to which any further migration to direct access would be consistent with a series of identified objectives … [that] include consistency with the state's greenhouse gas reduction goals, preventing *any increase* in criteria air pollutants and toxic contaminants, ensuring system reliability, and preventing undue cost shifting. If the reopening of direct access would not be consistent with these objectives, the Commission may not recommend further changes to state law.

In sum, in reply to the opening post-workshop comments of AReM and DACC, the question of *whether or not* to further expand DA in California is squarely before the Commission as it makes its recommendations.

As explained more fully below, the only reasonable recommendation the Commission can make in light of the requirement that the recommendations "do not increase" emissions of

[3] *See also* TURN opening comments on the September 20, 2019 Ruling of Administrative Law Judge Powell ("September 2019 Ruling") (September 30, 2019) at 1; CalCCA reply comments on the September 2019 Ruling (October 7, 2019) at 2-4.

criteria pollutants and toxic air contaminants, that they "ensure" system reliability, and meet the other required statutory criteria, is that there be no reopening of DA unless and until market reforms are in place that assure satisfaction of those criteria.

II. SB 237's Criteria Pollutants and Toxic Air Contaminants Finding Requirement is Binary and is Not Demonstrated by IRP Compliance.

In opening post-workshop comments, AReM contends that SB 237's criterion that "recommendations do not increase emissions of criteria air pollutants and toxic air contaminants"[4] "is directly related to the IRP requirements, which specify that each LSE's IRP must 'minimize localized air pollutants.'"[5] As stated in CalCCA's opening post-workshop comments, [6] SB 237's requirement that the Commission's recommendations "*do not increase*" criteria air pollutants and toxic air contaminants is very different from the Integrated Resource Plan ("IRP") requirement that LSEs "*minimize* localized air pollutants."[7] SB 237's requirement is binary (the recommendations *must not increase* such emissions), and minimizing not the same as not increasing (i.e., minimizing emissions could still result in increases in emissions relative to the baseline levels). SB 237's language on criteria and toxic pollutants is also much more prescriptive than the "consistent with" language SB 237 uses in connection with GHG emissions.

SB 237's strict requirement relating to criteria and toxic air pollution emissions is entirely understandable. What the Legislature is talking about here is environmental justice. Criteria and toxic air pollutants tend to have the greatest impact on disadvantaged communities.[8] The

---

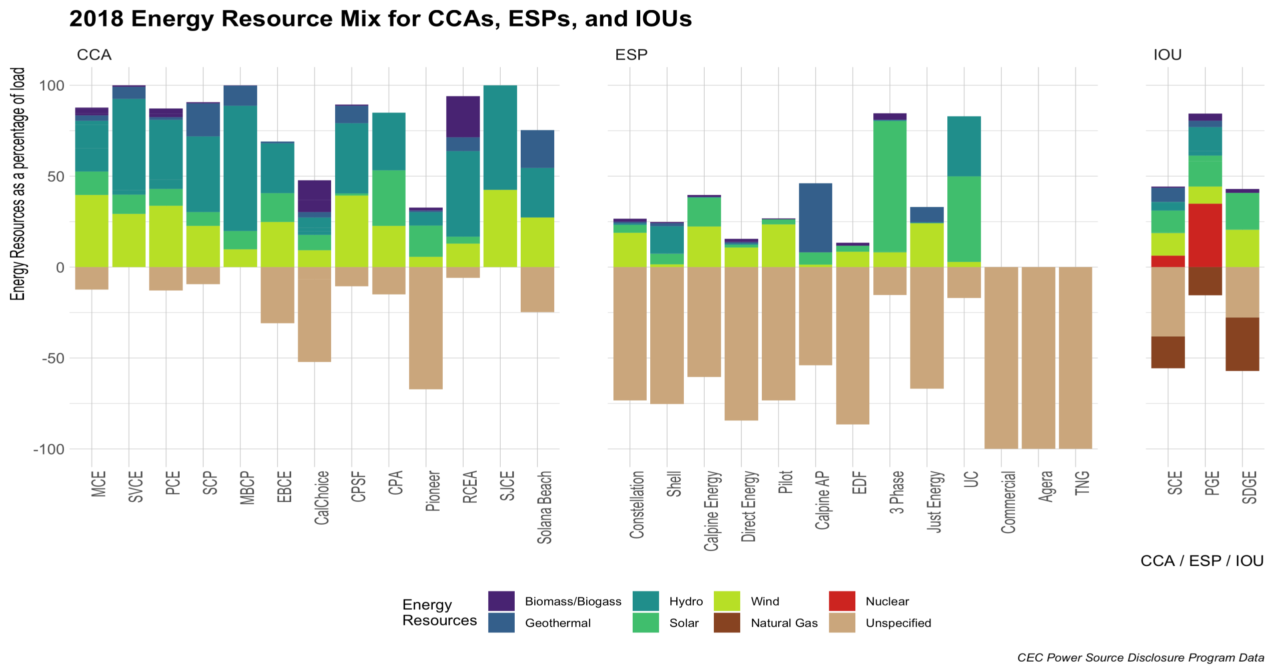
[4] Pub. Util. Code §365(f)(2)(B).
[5] AReM Opening Post-Workshop Comments at 7.
[6] CalCCA Opening Post-Workshop Comments at 14-15.
[7] Compare Pub. Util. Code §365.1(f)(2)(B) (emphasis added) to §454.52(a)(1)(I). There is a similar error in the scoping memo. *See* Amended Scoping Memo and Ruling of Assigned Commissioner Batjer (December 19, 2019) at 5-6.
[8] *See, e.g.*, California Environmental Justice Alliance, *Calenviroscreen: A Critical Tool for Achieving Environmental Justice In California* (2018).

Legislature made clear that the Commission may not make a recommendation with respect to a further DA reopening that could increase emissions in environmentally impacted, generally economically disadvantaged and minority communities. It is hardly surprising that the Legislature requires that a DA reopening not increase impacts at all, rather than just minimize them.

III. ESP Aspirations Regarding Emissions of Greenhouse Gases, Criteria Pollutants and Toxic Air Contaminants Do Not Equate to A Factual Basis for the Commission to Recommend a Further Direct Access Expansion.

A. In Fact, ESPs are Procuring More Brown Power Than Are Other LSE Types, Harming the State's Emissions Reduction Goals.

Several of the DA proponent Parties signing on to the Proposed Direct Access Reopening Schedule ("Joint Proposal") filed opening comments arguing that the environmental values and demand for clean energy among some large corporate customers should convince the Commission that the greenhouse gas ("GHG") and criteria air pollution statutory criteria will be satisfied. DACC reasoned that if ESPs don't provide clean energy, their market share will shrink. Yet, when one reviews data of what ESPs are actually selling to their customers, ESPs collectively sell a greater percentage of brown power than investor-owned utilities ("IOUs") or community choice aggregators ("CCAs"). A review of the ESPs' 2018 energy resource mixes as shown on their Power Content Labels ("PCL") demonstrates that ESPs' current customers are demanding less renewable energy than are customers of the CCAs and less renewable energy than IOUs are procuring for their customers:



In response to CCA representatives raising the implications of ESPs' track record around Renewable Portfolio Standard ("RPS") non-compliance in opening post-workshop comments, DACC characterizes such comments as merely anticompetitive. We disagree. The only way for the Commission to make the findings required by SB 237 is to rely on data, and the data show that ESPs are lagging relative to other LSE types with regards to the RPS. As TURN noted in opening post-workshop comments:

> [c]ompliance for the 2011-2013 period was first evaluated in 2017 with penalties enforced in 2019. The Commission found 6 ESPs to be noncompliant. Compliance for the 2014-2016 period Compliance for the 2014-2016 period was evaluated in 2019. The Commission found 3 ESPs to be noncompliant but has not yet enforced penalties.[9]

In fact, ESPs are the only LSE type found to be noncompliant with the RPS by the Commission based on the most recent RPS Annual Report.[10] While DACC argues that ESPs have been

[9] TURN Opening Post-Workshop Comments at 11-12.
[10] *See* California Public Utilities Commission, *2019 California Renewables Portfolio Standard Annual Report* (Nov. 2019) at 24-26, footnote 77, Table 16 ("2019 RPS Annual Report"), *available at*: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/2019%20RPS%20Annual%20Report.pdf.

operating since 1998 and therefore know how to comply with these requirements, the ESPs' collective history of noncompliance tells a different story.

In opening post-workshop comments, AReM argued that IRP modeling using a 2020 baseline should be used and compared to projected 2030 emissions to evaluate a downward trend in criteria pollutants if DA were to expand.[11] Relying on forecasted 2020 emissions as a baseline is unreasonable because such emissions are simply aspirational, not actual emissions levels. This is not germane to the current findings the Commission must make, which must be based on existing data sources.

Shell makes two lines of argument relating to DA customers' load profile that must be dismissed. First, it contends that customized energy supply agreements with DA customers are constructed to increase use of energy during periods of high renewable generation (i.e., the "belly of the duck"). ESPs could already enter such agreements today, but ESPs' track record to date does not provide any evidence that such prospective deals would be of sufficient impact to offset the increase in emissions that would inevitably flow from collectively shifting load from overall greener (incumbent) to browner (ESP) suppliers. The *hope* that such transactions might flourish in a way that is material to aggregate pollutant impacts is not a factual basis for the Commission to determine that any further expansion of DA transactions will not increase criteria air pollutants and toxic air contaminants.[12]

---

[11] AReM Opening Post-Workshop Comments at 7. This argument was also made by Direct Energy at the January 8 Workshop.

[12] TURN Opening Post-Workshop Comments at 11 (discussing Commission findings of ESP RPS noncompliance); CalCCA opening post-workshop comments at 5 and Figure 1 (noting that "incumbent [LSEs] have been procuring RPS and GHG-free resources beyond minimum requirements. ESPs by and large have not.") (citing 2019 RPS Annual Report Tables 2, 4 and 6); *id*. at 10-11 and Figure 2 (comparing Portfolio Content Category labels of ESPs to CCAs and demonstrating that ESPs are procuring more "brown power" and hence causing more emissions of criteria pollutants and toxic air contaminants as a percentage of load.).

The Commission already has implemented time-of-use ("TOU") rates, flexible capacity requirements, demand response programs and other policies targeted at tailoring load curves to supply curves. One much-discussed phenomenon around TOU rates is the emergence of "structural benefiters" and "structural non-benefiters." The concern Shell's point raises is ESPs will simply chase "structural benefiters" – customers whose use *already* is highest at hours of oversupply. This will not result in any shift in use patterns. TURN speaks to this when it observes that to "customers migrating to Direct Access are likely to be the lowest cost to serve within their rate class, an outcome that will drive up the average cost to serve the customers who remain with IOUs/CCAs."[13]

Next, Shell seems to boldly assert in its comments that CAISO's economic dispatch rules mean that the procurement portfolios of LSEs are actually irrelevant to actual state GHG, criteria pollutant and toxic air contaminant emissions.[14] Taken to its logical extension, this proposition would moot the entire purpose behind California's establishment of the RPS, the California Energy Commission's PCLs, and the IRP. The Commission must see through such attempts at obscuring the impact of ESPs' procurement records on achievement of the state's vital emissions reduction goals.

B. ESPs Are Underinvesting in Long-Term Contracts for New Renewable Supply, Further Harming Both Emissions Reduction and Reliability Goals.

Moreover, TURN's analysis of ESPs' RPS compliance found that ESPs "have a poor track record in using their procurement activities to drive investment in new generation infrastructure."[15] As TURN explained in opening post-workshop comments, DA advocates' assertion that 10 out of 13 ESPs have procured sufficient long-term contracts to meet SB 350's

[13] TURN Opening Post-Workshop Comments at 2.
[14] *See* Shell Opening Post-Workshop Comments at 6, 10-11.
[15] TURN Opening Post-Workshop Comments at 10.

requirements is misleading. ESPs have actually only identified long-term contracts equal to 9% of their retail sales for the 2021-2024 period.[16] To satisfy the requirements of SB 350, ESPs will need to obtain deliveries equal to approximately 26% of retail sales during this compliance period.[17] TURN also noted that ESPs chronically under-forecast load, with the effect of understating their compliance obligations. The additional 4,000 GWh of load eligible for DA authorized by SB 237 will make achievement of SB 350 forward contracting requirements all the more challenging, especially in face of typical short-term commitments from DA customers.[18]

Shell contends that it is speculative to predict that ESPs won't meet SB 350's 65% long-term requirement, because it doesn't begin to go into effect until 2021. CalCCA agrees that this requirement does not go into effect until 2021, and is evaluated over the 2021-2024 compliance period[19] and understands that LSEs are working hard to achieve these ambitious goals. But again, the collective ESP track record is not promising, as demonstrated by the lack of compliance with the RPS requirements in Compliance Period ("CP") 2 (2014-2016) for two of the three ESPs, assumedly related to compliance with the existing "*de minimus*" 0.25% long-term contract requirement.[20]

Shell further argues that "[a]s the DA market expands, ESPs will make longer term investments to meet their larger anticipated requirements."[21] Yet again, all the Commission has to use as the basis for its recommendation is the ESPs' collective track record. As TURN explained, "Direct Access providers typically have very short-term customer commitments

[16] *Id*. at 13.
[17] *Id*.
[18] *Id*. at 13-14.
[19] D.17-06-026 at 9, 38, OP 1.
[20] 2019 RPS Annual Report at 24-26. The long term contracting requirement requires that "a retail seller newly commencing operations in California must sign in the first compliance period of its operation in which any short term contract is signed, long term contracts with expected generation equal to at least 0.25% of its retail sales in the first year of its retail operations in California." D.12-06-038, OP 20.
[21] Shell Opening Post-Workshop Comments at 11.

(often just one year in duration) which frustrates the ability to enter into long-term resource commitments. These long-term commitments are needed to drive investments in new clean generating resources."[22] Other states like New York have not seen much in the way of RPS contributions by DA providers.[23] Most importantly, ESPs already serve a sizeable share of commercial load in IOU territories – and they have not been making the necessary long-term investments. Further, if the DA cap is raised, one would expect new ESP market entrants; which could result in no current ESP gaining any market share and thus facing ongoing challenges in meeting California's long-term renewables contracting requirements.

Finally, we note the argument made by DACC that any noncompliance with the RPS or other law by an ESP should not prevent the Commission from recommending further DA expansion, because noncompliance by a CCA wouldn't justify a moratorium on further CCA expansion. As stated in CalCCA's comments on the September 2019 Ruling, this proceeding is not about CCAs, who operate under an entirely different statutory framework. Regardless, CalCCA does not believe the Commission would or should let any LSE or group of LSEs systematically escape compliance with state mandates.

IV. To Be Consistent with SB 237's Required Statutory Findings, the Commission Should Recommend that Several Foundational Policies Must Be Implemented Prior to Authorizing Additional Direct Transactions.

---

[22] TURN Opening Post-Workshop Comments at 2.

[23] "[T]the record does not establish that ESCOs have provided significant contributions to the State's progress toward achieving its 2016 clean energy goal of 50% renewables by 2030." NYPSC Order at 76. Note that ESCOs are energy service companies that are akin to energy service providers in California. As a result of this finding, the NYPSC imposed a minimum annual renewables percentage requirement on ESCOs that is 50% higher than the existing Tier 1 LSE obligation (but in no case greater than 100%) and "[o]nce the Tier 1 LSE obligation reaches 50%, the products will be required to be 100% renewable, and that requirement will remain fixed as the Tier 1 LSE obligation increases above that level." *Id*. at 77. The NYPSC went on to explain "it makes little sense to permit ESCOs to offer renewably sourced commodity if the percentage of renewable energy is equal to or less than what is obtainable from the NYISO spot market or what is offered currently by the utilities. This requirement strikes the proper balance between the recognized value of incremental additions of renewably sourced energy against the need for a floor that protects customers against misleading claims regarding 'green' ESCO products." *Id*. at 78.

CalCCA agrees with opening post-workshop comments filed by Pacific Gas & Electric Company ("PG&E"), Southern California Edison Company ("SCE") and TURN that several significant market structure policies must be in place before DA can be expanded further.[24] Common to these commenters was a call for:

- Resolution and implementation of the central procurement entity structure;
- An established Provider of Last Resort ("POLR"), particularly in light of recent expressions by IOUs that they do not wish to take on this role; and
- Clarity around policies to prevent undue cost-shifting, such as further implementation of open issues relating to the Power Charge Indifference Adjustment ("PCIA").

SCE and TURN also noted that the IRP process is still very new and untested.[25] CalCCA agrees, noting that time is needed to see how the IRP program moves from theory to implementation. SCE further notes that the Commission's planned integration of IRP and RPS reporting should be implemented prior to making these changes.[26] TURN further urges that additional policies be "in place (and validated through real-world experience) before any additional expansion of direct access can be considered" including:

- Updated emissions accounting protocols that can accurately calculate and assign criteria pollutant and Greenhouse Gas emissions to unspecified (system) power purchased by LSEs.
- Revised rules governing confidentiality that provide more real-time transparency into the retail and wholesale activities of ESPs.[27]

CalCCA agrees with these parties that resolution and implementation of such rules are necessary before DA can be expanded to enable the Commission to make the findings specified in SB 237.

Several ESPs and DA advocates acknowledge the current policy uncertainty. For example, Commercial Energy discusses how Local Resource Adequacy capacity constraints

---

[24] PG&E Opening Post-Workshop Comments; SCE Opening Post-Workshop Comments at 1-3; TURN Opening Post-Workshop Comments at 3-4.
[25] SCE Opening Post-Workshop Comments at 2; TURN Opening Post-Workshop Comments at 5-6.
[26] SCE Opening Post-Workshop Comments at 7-8.
[27] TURN Opening Post-Workshop Comments at 3-4.

could be mitigated if IOUs could sell and optimize their portfolio, but that the Commission hasn't acted on this yet in PCIA Working Group 3.[28] CCAs certainly agree with this proposition, yet assert that it further supports a recommendation to hit the pause button on a further DA reopening in order to make the required findings. Both Commercial Energy and EPUC acknowledge in their opening comments that whether there will be a central buyer, and how this framework will be structured, is still uncertain.[29] Per EPUC:

> [T]he problem is not a function of adding LSEs to the mix; instead, the problem arises from a system that may provide an economic incentive not to comply. A backstop procurement framework to address noncompliance, potentially through a central buyer, may be required to address any potential erosion of carbon reductions.[30]

While CalCCA agrees with EPUC that these significant structuring issues must be resolved, we reach a different conclusion about the impact of the current uncertainty on the Commission's task in Phase 2. In light of the required findings and the structure of SB 237 as explained above, the only recommendation the Commission can make in light of these moving targets is to not recommend a further DA expansion at this point in time.

Several ESP parties argue that load migration to CCAs is happening despite policy issues being unresolved so that should not prevent a further DA reopening. This is a false equivalence. The Legislature made clear from the moment it created them that CCAs are not a subset of ESPs.[31] CCAs differ significantly from ESPs in their governance structures, commitment to GHG emissions reductions, and in that they serve *all* customers in their territory by default, and will continue to serve all customers on a tariffed basis – not simply the most profitable customers under one-off arrangements. Transparency is another big difference between ESPs and CCAs.

---

[28] Commercial Energy of California Opening Post-Workshop Comments at 3-4.
[29] *Id*. at 4; EPUC Opening Post-Workshop Comments at 5, footnote 8; *id*. at 7.
[30] EPUC Opening Post-Workshop Comments at 7.
[31] Pub. Util. Code §218.3(a).

While Shell's opening comments defended the ESP's aggressive confidentiality assertions as being inherent to their business of negotiating bilateral contracts with large corporate customers,[32] TURN explained how such opacity hinders the Commission (and other stakeholders) from evaluating and ensuring compliance with California's environmental and reliability goals.[33] Moreover, as TURN pointed out at the January 8 Workshop, CCA customers tend not to opt-out, whereas DA customers have little commitment to their retail providers and thus ESPs experience far more churn in customers that they serve at any one time. The uncertainty of ESPs' customer base makes it irrational for ESPs to invest in long-term contracts and new generation, as Commercial Energy's representative expressed at the January 8 Workshop. As CCA representatives expressed at the workshop, the primary driver for communities establishing CCAs is to exceed the incumbent utility's RPS procurement and other environmental impacts and to fight the deleterious effects of climate change on their communities.[34] Simply put, as mission-driven government agencies, CCA expansion does not raise the same concerns that direct access expansion does.

V. Current Consumer Protections for DA Customers Are Untested in an Uncapped Retail Market, and the Commission Should Carefully Evaluate Lessons from Other States.

AReM, DACC, Commercial Energy and the California Large Energy Consumers Association argue that existing statute and Commission precedent is sufficient to protect customers under further DA expansion. Yet (to state the obvious), ESPs currently cannot market to all nonresidential customers. As DACC explained, all of their customers must have the

---

[32] Shell Opening Post-Workshop Comments at 12-13.

[33] TURN Opening Post-Workshop Comments at 2 ("Direct Access providers routinely assert greater claims to confidentiality than other LSEs and do not provide transparency on terms of their contracts with customers or energy supplies. Shielding greater volumes of information from disclosure will undermine the ability of the public and policymakers to assess progress and meaningfully participate in the oversight process."). *Id*. at 6-7.

[34] *See* https://cal-cca.org/cca-impact/ (quantifying the collective long-term renewables and energy storage procurement of CCAs, RPS percentages of CCAs, including low percentages of unbundled RECs).

resources to enter the queue, negotiate bilateral contracts with ESPs and ensure that proper filings are made with the Commission.[35] In an expanded or fully reopened nonresidential retail market, many customers will not be so "sophisticated."[36] If the DA cap is lifted for nonresidential customers, there will be no queue and we can envision far more form contracts and fewer arms'-length negotiations as ESPs seek economies of scale and existing or new ESPs market to a broader range of nonresidential customers. Thus, existing law is untested in an expanded DA setting in California. But, what we see in other states like New York, Illinois and Texas does give rise to consumer protection concerns.[37]

As DACC notes, sections 394.5 and 366.5 do provide special additional requirements for service to small commercial in recognition that they are likely to be preyed upon. As noted by DACC, §394.5 focuses on requirements for disclosure of pricing and terms & conditions of service while §366.5 puts in place procedures designed to make "slamming" a customer more difficult. These requirements do not, however, address the full range of concerning activities.

---

[35] DACC Opening Post-Workshop Comments at 5.

[36] *Id*.

[37] *See*, *e.g.*, https://www.dallasnews.com/news/watchdog/2019/08/23/texans-pay-more-for-electricity-now-than-other-major-markets-a-wholesale-price-record-is-to-blame/ (spiking rates for ESP customers in Texas); *Competing to Overcharge Consumers: The Competitive Electric Supplier Market in Massachusetts*, Jennifer Bosco, National Consumer Law Center (April 2018), *available at*: https://www.nclc.org/images/pdf/pr-reports/competitive-energy-supply-report.pdf; NYPSC Order (noting that adoption of new marketing standards "are the result of a gradual iterative process of increasing the specificity and restrictiveness of the applicable standards to ESCO marketing practices resulting from persistent, unacceptably high numbers of customer complaints alleging ESCO deceptive marketing."); NYPSC Press Release at 2-3 ("The complaint rate for ESCOs remains unacceptably high. Between 2014 and 2016, the Commission received more than 11,000 initial complaints about ESCOs. … Throughout these proceedings, non-ESCO parties raised many concerns about the current operation of the retail energy market. The Commission shares those concerns, particularly regarding the lack of easily accessible and comprehensible product and pricing information and the number of complaints alleging that bad-acting ESCOs were exploiting customers. Thus, the Commission concludes that significant changes to provisions governing retail access are needed to provide adequate protections for New York customers. If market participants are unwilling or unable to provide material benefits to customers — beyond those provided by utilities — at reasonable prices, the market serves no proper public interest purpose and should be ended.").

The Energy Division's Gap Analysis[38] lays out a series of consumer protection concerns, summarized at pp. 73-75. Other states' experiences surface further concerns regarding consumer protection, notwithstanding extensive webs of consumer protection laws and regulations.[39] The New York PSC has devoted decades to consumer protection problems. Yet as of December 2019, the PSC found:

> Based upon the number of customer complaints that continue to be made against ESCOs, and the likely need for increased enforcement activities, the large number of ESCO customers that pay significant premiums for products with little or no apparent added benefit, and the market's dearth of innovation and value-added services, it appears that a material level of misleading marketing practices continues to plague the retail access market. Whether or not ESCOs are purposefully deceiving or preying on unsuspecting customers, many ESCO marketing practices nevertheless could be perceived by massmarket customers as misleading. Moreover, these problems persist despite the Commission's actions over the years to improve the function of the market, through efforts aimed at both limiting undesirable behavior of ESCOs and their representatives and by eliminating barriers and otherwise supporting ESCOs' business activities.[40]

Will the Commission allow the type of predatory marketing to increase customer sign ups - such as offering sports tickets, gift cards or teaser rates - to small commercial customers as seen in New York?[41] In Texas, customers are being offered energy pricing that decreases the cost of energy as the energy consumer consumes more energy.[42] Will the Commission prohibit this type of pricing behavior as inconsistent with state policy goals concerning conservation? What will the Commission do to ensure energy customers understand that their ESP may be serving them with 100% brown power during the term of their contract? In light of the decisive action taken by the New York PSC just last year, the Commission must examine predatory behavior and other

---

[38] *California Customer Choice Project - Choice Action Plan and Gap Analysis*, issued December 2018 (the "Gap Analysis").

[39] *See* CalCCA Opening Post-Workshop Comments at 21-22.

[40] NYPSC Order at 88-89.

[41] NYPSC Press Release at 3.

[42] *See*, *e.g.*, https://www.comparepower.com; *see also* https://www.texaspowerguide.com/2017/reliant-high-use-plan/

issues and ensure its consumer complaint process and enforcement tools will be sufficient. Based on the concerns raised in the Gap Analysis, and the problems seen in other markets, ensuring the Commission has the appropriate consumer protection rules and oversight mechanisms in place is a valid area of focus.

VI. ESP Parties Have Not Demonstrated that the Commission Can Recommend a Further DA Expansion in a Manner that Does Not Cause Undue Cost Shifting.

As TURN discussed in the January 8 Workshop and in opening comments, ESPs tend to cherry-pick the customers that are least expensive to serve.[43] This may be economically rational behavior for a private company without an obligation to serve all customers within a certain territory, but one that is highly likely to result in cost-shifts to bundled customers who would become more costly to serve as a result. It's telling that ESP comments focus exclusively on their service to the largest commercial and industrial ("C&I") customers – that is a warning to the Commission on which market segments they intend to serve and is directly demonstrative of the cost shifts that will ensue.

In opening post-workshop comments, AReM cavalierly argues that "[i]f an ESP fails and returns any small commercial customers *en masse*, they return to bundled utility service."[44] This is cause for significant concern and scrutiny in light of current market uncertainty, the bankruptcy of the Country's largest utility and signals reminiscent of the last energy crisis. Pursuant to SB 237, both the cost-shifting and reliability implications must be carefully considered.

Moreover, while §365.1(f)(2)(D) focuses on cost-shifts to bundled service and DA customers, the fact is that more than one quarter of California customers in IOU territories are currently CCA customers, and this number is growing. These customers represent the full range

[43] TURN Opening Post-Workshop Comments at 18, 19.
[44] AReM Opening Post-Workshop Comments at 12, footnote 28.

of electric customers in California – residential, CARE, medical baseline, small non-residential to the largest C&I customers. While SB 237 focuses on bundled customers, the Commission has an obligation to protect all customers from cost-shifts. Moreover, the Legislature has expressed a clear intent for the Commission to support the formation of CCAs in SB 790 (Leno 2011).[45] Due to the cherry picking by DA providers, there will be a cost-shift to CCA customers if DA is further expanded. CCAs have procured electricity on behalf of nonresidential customers, and have been working hard to comply with SB 350's long-term contract requirements.[46] While ESPs argue to the contrary, the Commission needs to take this customer impact into account when it makes its recommendation.

AReM, DACC and Shell argued in opening comments that CCAs could impose exit fees on their customers if load migration to ESPs caused undue cost-shifting to existing CCA customers. While CCAs, as local government agencies, would certainly never want to be in a position to have to impose such fees on their customers, CalCCA agrees that CCAs have the authority to do so and that Electric Rule 23 requires the distribution utility to collect such fees from customers who have departed CCA service. PG&E Rule 23 states "PG&E shall include CCA charges on the [ratepayer's] bill" and PG&E "shall process customer payments and transfer amounts paid toward CCA charges to the CCA when the payments are received..." This obligation is neither qualified nor conditioned on whether the ratepayer is currently a CCA customer. Rather, the implication within PG&E's tariffs, as well as the Public Utilities Code and Commission decisions, is that all CCA charges shall be included on the bill provided by the

[45] *See, e.g.*, Pub. Util. Code § (PUC 366.2(c)(9)("All electrical corporations shall cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs. ….The commission shall exercise its authority pursuant to Chapter 11 (commencing with Section 2100) to enforce the requirements of this paragraph when it finds that the requirements of this paragraph have been violated.")

[46] As noted in CalCCA's opening comments, CalCCA members have collectively entered into contracts for new-build projects totaling over 3,400 MW of renewable generation, capacity and energy storage. CalCCA Opening Post-Workshop Comments at 1.

distribution utility so long as the charges are applicable to the ratepayer. MCE recently sent a letter to PG&E seeking to confirm this understanding, but PG&E has not yet responded. Hence, in our opening post-workshop comments, CalCCA asked the Commission to consider this matter as part of its study pursuant to SB 237. In its decision on Phase 2, we ask the Commission to confirm that this is indeed the case, particularly in light of the risk to so many California customers of a cost-shift as a result of potentially significant load migration to ESPs.

VII. CalCCA Response to the Joint Proposal & Conclusion

For the many reasons set forth herein and in CalCCA's opening post-workshop comments, as well as the concerns raised at the January 8 Workshop and opening comments filed by TURN, the Public Advocates Office, PG&E and SCE, any recommendation by the Commission for the Legislature to further reopen DA transactions at this point in time cannot be reconciled with the four statutory findings the Commission is required to make. The Joint Proposal is therefore unreasonable and would lead the Commission down a path that doesn't comply with SB 237.

January 27, 2020

Respectfully submitted,

/s/ Sheridan Pauker

Sheridan Pauker
Keyes & Fox LLP
580 California St., 12th Floor
San Francisco, CA 94104
510.314.8202
spauker@keyesfox.com

Counsel to the California Community Choice Association

FEBRUARY FILINGS

Stakeholder Comments of the California Community Choice Association

Maximum Import Capability Stabilization and Multi-Year Allocation Initiative: Straw Proposal

Submitted to: regionaltransmission@caiso.com

Submitted by	Organization	Date Submitted
Evelyn Kahl, Buchalter (415) 227-3563	California Community Choice Association[1]	*February 12, 2020*

CalCCA appreciates the opportunity to comment on the CAISO's Maximum Import Capability Stabilization and Multi-Year Allocation Straw Proposal and wishes to acknowledge the CAISO staff for their efforts undertaken to draft the proposal.

This document focuses on the calculation of MIC rather than the allocation proposal and is in three parts. CalCCA is generally supportive of the CAISO's multi-year approach to MIC allocations and believes this is a vast improvement over the present rules. That said, CalCCA is not commenting on implementation details in these comments at this time. CalCCA is continuing to develop its view on the MIC allocation process and anticipates providing comments on important aspects of this issue (e.g., load migration) at a later date.

In this document we first, we describe some of our assumptions regarding the problem that the CAISO faces in setting MIC values in aggregate and by branch group. Second, we offer comments/recommendations. Third, we end with two questions for consideration by the CAISO and parties in this stakeholder process. Some assumptions are restatements of those the CAISO has already made but are included here because of their relevance to our comments.

We include assumptions because i) they guide the rest of our comments, ii) we wish to understand the CAISO's problem(s) and proposal solution(s) better, and iii) we wish to help others understand the assumptions underlying our comments in order to interpret and respond to our comments.

[1] California Community Choice Association represents local government Community Choice Aggregation electricity providers in California members, including Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, East Bay Community Energy, King City Community Power, Lancaster Choice Energy, MCE, Monterey Bay Community Power, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy.

Assumptions:

- The CAISO has limited ability to forecast the simultaneously feasible optimal power flow across the WECC system, given uncertainty regarding supply volume, supply and transmission arrangements, and relative marginal cost of resources among and within each balancing authority area.
- The CAISO does not know ahead of time when the period of greatest system need will be in any given window of time (year, season, month, day).
- The period of peak demand and peak imports may not perfectly align with the period of peak system need and available import capability at such time.
- Uncertainty, especially regarding internal power flows resulting from internal load and generation statuses, suggests conservative estimates for branch group MIC may be warranted; however, there are risks that being too conservative will impede the efficient and equitable treatment of internal and external resources.
- While the total physical import capability of all interties is 44,400 MW, the interplay between external and internal power flows limits the actual amount of net imports that can be accommodated during a delivery period/operating hour (the CAISO's Operating Procedure 6150 limits net imports to 12,800 MW).
- Historical import data is imperfectly representative of future available import capacity.
- Stabilization of MIC and multi-year allocation will increase certainty needed by market participants to transact for imported capacity.
    - Stabilization of MIC using any chosen historical period risks underestimating actual import capacity during the actual operating period.
- A forward-looking MIC methodology is challenging for several reasons:
    - CAISO does not know what actual internal power flows will be (input variables include gas prices, generator outages/derates, transmission outages/derates, weather, VER production, etc.).
    - CAISO has limited information on current and future resource fleets outside of its territory.

Comments

CalCCA offers the following items for consideration as the CAISO develops the revised straw proposal:

- Principle: MIC calculation should be a best unbiased estimate of actual operating conditions.
- Comment: CAISO should consider a forward-looking (WECC-wide) analysis.
    - For example, a full forward-looking WECC-wide simultaneously feasible/optimal power flow production cost model able to develop ranges of MIC values by branch group for multiple realistic CAISO stressed grid conditions may be feasible and valuable (positive cost/benefit of developing the new methodology).
    - This analysis should also take into account how much potential import capacity is reserved for the EIM market, and how much this capacity can be counted on to deliver energy into California when needed.
- Comment: CAISO should estimate how results from an historical analysis (including the one proposed in the Straw Proposal) differ from an ideal/perfect-information forward-

looking analysis. While the results of a perfect forward-looking analysis are necessarily unknown, striving to minimize the gap between the outputs of what is implemented, and what a perfect set of outputs would be should be a priority.
  - Perhaps the CAISO could use back-testing with best available information to make such an estimate.
  - Estimates must also consider how the historical analysis may include only un-stressed periods in the West that fail to account for potential future stressed conditions (for example, drought through-out the West). In other words, if we know the input data are unrepresentative or otherwise biased against projected operating conditions, such insights should be acknowledged and addressed as best as possible (see “best unbiased estimate” principle).
- Comment: CAISO should continually identify data it does not have that would help improve accuracy of the methodology (historical or forward-looking).
- Comment: CAISO has described peak demand as the period of interest in deriving MIC values; CAISO should consider whether net demand (demand minus in-front-of-the-meter VER production plus/minus net storage dispatch) would better reflect time periods of greatest need, or whether the analysis should consider both periods.
- Comment: Allow MIC calculation to remain flexible to changing resource fleet by redefining objective from determining import capacity at period of system peak to import capacity at period of greatest system need.
  - For example, if system need increases when internal resource production drops off, the import capacity of greatest relevance may be post-peak, in which internal and external resources are not competing to serve load but are complementary to meeting the objective of optimal commitment and dispatch (WECC-wide). A MIC process that restricts branch group capability to those most limiting periods in terms of how much energy can be imported, and is then applied to other periods where such actual limits are much higher, this may distort and adversely affect the RA market, violating the principle of equitable in-state and out-of-state resources.
- Comment: CAISO should consider whether some description of Operating Procedure 6150 that would be valuable to market participants, can be made public.

Questions:

- Will the aggregate MIC value appropriately align with CAISO system needs over the medium and long-term, as these system needs evolve over time with a changing supply portfolio (net peak demand pushing the greatest need for capacity and energy into the evening hours, and perhaps into the overnight and early pre-solar-ramp morning hours; the MIC methodology should be flexible enough to accommodate a storage-heavy CAISO supply portfolio)?
- Will the adopted rules align with, or at least not conflict with, the RA-CPE as contemplated in the settlement proposal within CPUC Proceeding R.17-09-020?

February 11, 2020

Commissioner Martha Guzman Aceves
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Dear Commissioner Guzman Aceves,

The California Community Choice Association (CalCCA) submits this letter to the Commission to express support for GRID Alternatives' (GRID) Petition for Modification (PFM) of Decision 18-06-027 to expand the geographic and income eligibility for the Disadvantaged Communities Single-family Solar Homes (DAC-SASH) program.

CalCCA is a trade association that represents the state's Community Choice Aggregators (CCAs). More than 170 communities (cities, towns, counties) in California are providing CCA service to more than 10 million customers — numbers that will see significant growth in 2020-2021. GRID and CCAs share a common goal of making clean energy and green jobs accessible to underserved communities and have collaborated on several initiatives to advance solar access to low-income customers and communities (list of projects on page 2).

CalCCA agrees with GRID's assertion that the DAC-SASH program's current income limit disproportionately excludes households living in high cost-of-living areas in the state. Changing the income eligibility for DAC-SASH to 80% AMI, as GRID recommends in the PFM, would allow more low-income homeowners to take advantage of solar technologies, better achieving the aims of D.18-06-027.

The 80% AMI definition models the current SASH program and more equitably addresses the extremely wide variance among cost-of-living in California. As it now stands, the DAC-SASH program unfairly excludes low-income households residing in disadvantaged communities in the Bay Area, Los Angeles, and San Diego, for example.

We support GRID's petition for expanding this program because it will include communities that need critical access. We appreciate your leadership to ensure equitable access to solar energy with the DAC-SASH program.

Sincerely,

Beth Vaughan
Executive Director, CalCCA

The list below is a brief summary of GRID Alternatives' work with CCAs to date summarized by category.

Low-Income Single-Family and Multifamily Solar

- Gap funding for low-income single-family homes (MCE, Monterey Bay Community Power)
- Gap funding for multifamily affordable housing (MCE)
- Co-marketing for no-cost solar programs (MCE, Sonoma Clean Power, Redwood Coast Energy Authority)

Electric Vehicles

- Funding for free or highly subsidized EVs for community organizations (Sonoma Clean Power, Lancaster Choice Energy)
- Low-income incentives for EVs and free chargers (Sonoma Clean Power)
- Funding for single family & multifamily charging infrastructure (MCE, Redwood Coast Energy Authority)
- Technical assistance for multifamily charging infrastructure (MCE, Peninsula Clean Energy)

Energy Efficiency & Other

- Energy efficiency audits and rebates for multifamily affordable housing (MCE)
- Funding for main service panel upgrades (pending)

Low-Income Community Solar

- Pilot Community Solar FiT project (MCE, San Joaquin test project)
- Advising on Community Solar Policy and partnering on CSD grant (Clean Power Alliance)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions	Rulemaking 18-12-005 (Filed December 13, 2018)

REPLY COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED ADDITIONAL DE-ENERGIZATION GUIDELINES

David Peffer
BRAUN BLAISING SMITH WYNNE P.C.
555 Capitol Mall, Suite 570
Sacramento, CA 95814
Tel: (916) 326-5812
E-mail: peffer@braunlegal.com

On behalf of:
The California Community Choice Association

February 26, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions	Rulemaking 18-12-005 (Filed December 13, 2018)

REPLY COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED ADDITIONAL DE-ENERGIZATION GUIDELINES

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the January 30, 2020 *Administrative Law Judge's Ruling Requesting Comments* (the "ALJ Ruling"), the California Community Choice Association ("CalCCA") hereby submits the following reply comments addressing points raised in a number of parties' February 19, 2019 opening comments on the Energy Division's January 30, 2020 *Proposed Additional and Modified De-Energization Guidelines In Addition To Appendix A Of the De-Energization Phase 1 Decision (D.19-05-042) and Resolution ERSB-8* (the "Staff Proposal"). CalCCA was granted party status in this proceeding via email ruling on June 17, 2019.

I. REPLY COMMENTS

A. Working Groups And Advisory Boards

i. Working Groups Proposal

CalCCA agrees with the wide range of parties who support the working groups proposal in principle, but believe that additional detail and requirements are essential to its success, and strongly opposes requests by Pacific Gas and Electric Company ("PG&E") and Southern California Edison ("SCE") to weaken the working groups.

CalCCA agrees with the Joint Local Governments, Rural County Representatives of California ("RCRC"), and the City of San Jose ("San Jose") that the "regions" that each working group is to cover should be clearly and specifically defined by the Commission, and further stresses the importance of ensuring that the task of defining the working group "regions" (as well as similar determinations regarding working group membership, meeting duration and frequency, and information access) be specifically established in the Commission's PSPS rules, not left up to the IOUs. In opening comments, CalCCA proposed that working group regions be defined as the pre-existing operational areas used in emergency management and response planning.[1] In light of RCRC's persuasive arguments in favor of county-level working groups,[2] CalCCA amends its proposal, and asks that the Commission require the formation of a separate working group for each county and each tribal government within each IOU's service territory.

CalCCA strongly agrees with the Joint Local Governments that the focus of the working groups should be on identifying and developing going-forward improvements to the utilities' PSPS programs.[3] The utilities' handling of past PSPS events is already the subject of ample review in the OII proceeding. While CalCCA strongly supports the identification of lessons learned, these lessons are only useful in the context of assessing the of the adequacy of, and recommending improvements to, the IOUs *current* PSPS programs. This assessment should occur both at the local level (through the working groups) and at the IOU-level (through the advisory board).

CalCCA strongly opposes proposals by PG&E and SCE that would effectively weaken the working group requirements. PG&E proposes that the required meeting frequency for the working groups be reduced from monthly to quarterly, and that the number of stakeholder groups included in the working groups be reduced.[4] SCE proposes that the working group and advisory board meetings be combined and held twice a year.[5] As justification for these extraordinary requests, both SCE and PG&E point to their existing community outreach efforts, which they either state (SCE) or imply (PG&E) already fulfill the purpose of the working groups proposal, rendering Commission required working groups unnecessary.[6]

In order to provide any meaningful benefit, the working groups (and advisory boards) must be established and overseen by the Commission and must be able to perform their functions independently from IOU influence and control. The existing programs lauded by SCE and PG&E were created and organized by the utilities. Every key element of these programs, from meeting times and frequency, program purpose, meeting agenda, information sharing, and who is included or excluded from participation in these programs is determined by the IOU. For instance, PG&E has

---

1 CalCCA Opening Comments at 5-6.
2 RCRC Opening Comments at 3.
3 Joint Local Governments Opening Comments at 7.
4 PG&E Opening Comments at 7.
5 SCE Opening Comments at 3-4.
6 *See*, SCE Opening Comments at 4; PG&E Opening Comments at 2-6.

broadly excluded CCAs from its "listening sessions" and a range of other PSPS-related meetings, despite the fact that CCAs are both public safety partners and local government agencies. Even a high-level review of party comments on PG&E's post-event reports demonstrates systematic failures to communicate with local governments and public safety partners. PG&E has repeatedly refused to share essential PSPS-related information with local governments and CCAs. In light of this dismal track record, it is difficult to imagine that PG&E's outreach efforts will satisfy the goals of the working groups.

Similarly, SCE's PSPS outreach efforts, such as "meeting every other week with representatives from county Emergency Management Agencies across the SCE territory charged with local emergency planning"[7] do not provide a formal, guaranteed, Commission-overseen mechanism that allows local government agencies, CCAs, public safety partners, and other interested parties to share information with SCE, have guaranteed access to all relevant PSPS information, and develop meaningful assessments, feedback, and recommendations regarding SCE's PSPS plans.

PG&E and SCE's requests to reduce the frequency of the working group meetings must be rejected. Monthly meetings are the minimum meeting frequency needed to produce substantial results before next fire season. Assuming the Final Decision is issued in Q2 2020, there would only be time for 1 or possibly 2 quarterly working group meetings.

PG&E's request to narrow the list of required representatives to be included in the working group should likewise be rejected. To be effective the working groups should represent a diverse range of perspectives and interests from each county. All IOUs would benefit greatly from hearing from these local voices, and the communities and agencies represented in the working groups would benefit greatly from increased engagement with the IOUs and access to information regarding the IOUs' PSPS programs and plans.

ii. Advisory Boards Proposal

CalCCA views the formation of independent, service territory-level advisory boards that work with both the IOU and the local working groups as critical to producing meaningful PSPS program improvements. Above all, the advisory boards must be structured to provide necessary and critical recommendations to the IOU, and not for the IOU to disseminate information unidirectionally

---

7 SCE Opening Comments at 4-5.

to carefully selected individuals. For this reason, the Commission should reject SCE's proposal to combine the advisory boards and working groups and have them meet twice yearly.[8] Similarly, the Commission should clarify that PG&E's proposed "advisory committee" which would be composed of 8-10 local and tribal government representatives (presumably selected by PG&E), would meet quarterly on an ad-hoc basis, and would be limited to 90 minute meetings,[9] does not comply with the advisory board requirements and is not a substitute for the required advisory board. Restrictions of this nature weakens the Commission's intent to create a more collaborative and inclusive process.

B. De-Energization Exercises

CalCCA agrees with the near-consensus support for the Staff-Proposal's de-energization exercises, but agrees with many parties that the proposal should be improved. In addition to the modifications to the proposal recommended in CalCCA's opening comments, CalCCA supports the inclusion of the following modifications:

- CalCCA agrees with San Jose that the "regions" covered by the planning exercises should cover no more than 2 counties at most,[10] but recommends that the regions be limited to the county level in order to align with the working group regions
- CalCCA agrees with the Center for Accessible Technology ("CforAT") that telecommunications company representatives should be included in exercises, and that exercises should include consideration of communications facilities and outages.[11]
- CalCCA agrees with RCRC and CforAT that exercises should include planning for disasters that occur during PSPS events (such as the Kincade fire).[12]
- CalCCA agrees with the California Public Advocates Office ("CalPA") that all relevant public safety partners should be included in the exercises,[13] and notes, in particular, the importance of including CCAs in the exercises.

CalCCA further supports several proposals to expand the exercises to better consider the needs of Access and Functional Needs ("AFN") individuals and communities:

---

8 SCE Opening Comments at 6.
9 PG&E Opening Comments at 5-6.
10 San Jose Opening Comments at 4.
11 CforAT Opening Comments at 5.
12 RCRC Opening Comments at 4; CforAT Opening Comments at 5-6.
13 CalPA Opening Comments at 6.

- CalCCA agrees with RCRC that exercises should include scenarios for addressing the needs of AFN populations, including providing backup power, transportation, and other accommodations for those in need.[14]
- CalCCA agrees with CforAT that exercises should include planning for how to respond to people with medical needs, identifying people at risk and providing appropriate services and support, which could include:
  - Evacuation or transport to a safe location
  - Providing backup power to homes of at risk individuals
  - Providing necessary support including items like oxygen tanks or replacement medication
  - Plans for food (beyond IOUs' proposed "snacks").[15]

C. Notice Requirements

i. Public Notice Requirements

CalCCA joins the wide range of parties expressing general support for the Staff Proposal's public notice requirements. In particular, CalCCA joins RCRC, CforAT, and San Jose, among others in strongly supporting the requirement that the public be provided with precise and accurate maps and outage information.[16]

In addition, CalCCA joins RCRC in supporting SCE's proposal (from its Wildfire Mitigation Plan) to provide PSPS notice to all cell phones physically located in a planned PSPS area. CalCCA agrees with RCRC that this will help provide notice to non-account holders such as tenants, relatives, tourists, and domestic workers.[17] This proposal will also benefit those who live in an area not impacted by a PSPS event, but work or go to school in a PSPS-impacted area. CalCCA strongly recommends that the Commission amend the Staff Proposal to adopt this as a mandatory notice requirement for all IOUs, and require that the IOUs, in coordination with the telecom providers, have this capability in place no later than May 15, 2020.

ii. AFN Notice Requirements

---

14 RCRC Opening Comments at 4.
15 CforAT Opening Comments at 5.
16 RCRC Opening Comments at 5, CforAT Opening Comments at 7, San Jose Opening Comments at 5.
17 RCRC Opening Comments at 5.

CalCCA agrees with San Jose that the Staff Proposal should be expanded to adopt more thorough requirements for providing PSPS notification to AFN individuals.[18] As such, CalCCA requests that the Staff Proposal be amended to adopt the AFN notice requirements CalCCA previously proposed in its September 17, 2019 Phase 2 Proposal in this docket:

- For all AFN individuals, the IOUs should be required to continue attempts to provide notice of a planned or pending PSPS outage until they receive confirmation that the AFN individual has received notice.
- The IOUs should be required to keep records of all notification attempts, including the date and time and method of the notification attempt, the time that confirmation of the notification is received, and the method via which the confirmation was provided.
- The IOUs should be required to provide AFN individuals with notification through human phone calls and in-person visits if necessary, and may not rely solely on email, text-messages, or robocalls.[19]

CalCCA supports Santa Clara's proposal that the IOUs be required to notify local governments of Medical Baseline customers they were unable to contact. CalCCA recommends that this requirement be expanded to also include all AFN customers. The IOUs should also be required to provide detailed information regarding their attempts to provide AFN customers with notice and secure confirmation in their post-event reports.

D. Community Resource Centers

i. Role of Local Governments

In its opening comments, CalCCA proposed that the IOUs be required to defer to local government decisions regarding Community Resource Center ("CRC") siting, facilities, and operations; and defer to local governments that elect to plan and operate their own CRCs.[20] Based on its review of government parties' opening comments, CalCCA amend this proposal to add the following clarification:

- CalCCA's proposal in no way shifts the burden or responsibility for mitigating the impacts of PSPS events from the IOUs.

---

18 San Jose Opening Comments at 4-5.

19 *California Community Choice Association Proposal In Response To Assigned Commissioner's Phase 2 Scoping Memo And Ruling* at 22-24.

20 CalCCA Opening Comments at 17-18.

- If a local government elects to impose requirements for IOU CRCs or operate its own CRCs, the IOU still bears full financial responsibility for the CRC and is still required to provide all resources needed by the CRC.

CalCCA agrees with RCRC, LGSEC, Santa Clara and the Joint Local Governments that the IOUs should be explicitly required to fully fund and provide all reasonably needed resources to CRCs.

ii. Required Services at CRCs

CalCCA is concerned by the casual attitude towards CRCs demonstrated by some IOUs. PG&E, for instance, has previously proposed that CRCs provide "snacks" and cell phone charging. This ignores one of the "Overarching Guidelines" identified in the De-Energization Guidelines, the principle that the "consequences of de-energization should be treated in the same manner as any other emergency that may result in loss of power, such as earthquakes, floods, or non-utility caused fire events."[21]

CalCCA agrees with a number of parties who argue that CRCs should be required to provide standard emergency relief services beyond snacks and phone charging:

- CalCCA agrees with CforAT that the guidelines should be amended to require that CRCs have the capacity to function as emergency shelters, with the capacity to provide food, hygiene facilities, sleeping facilities, and power for medical devices and communication devices.[22]
- CalCCA agrees with CforAT that CRCs should account for the needs of people without transportation, and that the IOUs should be required to identify and provide transportation for people in need who otherwise cannot reach a CRC.[23]
- CalCCA agrees with TURN that IOUs should be required to provide Wi-Fi and communication access at CRCs.[24]

Based on the principles that PSPS events should be treated as emergencies and CRCs should be treated in the same manner as other emergency shelters, and parties' recommendations from

---

21 D.19-05-042, Appendix A (De-Energization Guidelines) at A2.
22 CforAT Opening Comments at 8.
23 CforAT Opening Comments at 8.
24 TURN Opening Comments at 4.

opening comments, CalCCA offers the following proposed addition to the Staff Proposal adopting a list of required services for CRCs:

- IOUs shall be required to provide the following services at IOU CRCs, and provide local government agencies with the resources needed to provide these services at their local government CRCs:
    - Device charging.
    - Wi-Fi and internet access.
    - Telecommunications access, including free telephone use.
    - Direct access to first responders and evacuation resources for medical emergencies.
    - On site first aid.
    - Access to adequate bottled/purified water to provide to the community in case tap water is contaminated or becomes unavailable.
    - Sufficient beds to:
        - Provide shelter in case residents are required to evacuate due to a concurrent disaster or PSPS-related issues.
        - Serve CPAP users and other medical device users.
        - Allow vulnerable individuals, including AFN individuals, to stay at the CRC and avoid exposure to heat and cold.
    - Cooling centers during hot weather.
    - Warming centers for communities where night temperatures drop dramatically.
    - Shuttles to/from public transport, hospitals/medical centers, and other key points.
    - Hygiene facilities.
    - AFN Accommodations.

iii. Travel Time Requirement

The Staff Proposal's proposed requirement that CRCs be located within a 30-minute drive of all PSPS-impacted individuals prompted mixed reactions in opening comments. Commenters noted the challenges faced by individuals with mobility limitations and those who rely on public transit (which may not be operational during PSPS outages), as well as the significant differences between a "30 minute drive" in an urban area and a "30 minute drive" in a rural area.

In light of these comments, CalCCA recommends that the hard and fast "30 minute drive" rule be replaced with the following, more flexible requirement:

- CRCs shall be sited in locations that are reasonably accessible to all residents in the CRC's coverage zone, regardless of the residents' mode of transportation or transportation limitations.
- Prior to initiating a PSPS event, the IOU shall ensure that all potentially impacted customers are within the coverage zone and have reasonable access to a CRC, including residents who are without cars, depend on mass transit, or are mobility impaired.
- The size and service capacity of the CRC should be adequate to serve the population of the CRC's coverage zone.
- CRC planning should focus on those areas most likely to experience PSPS outages.

The IOUs' concerns regarding the burden of the Staff Proposal's CRC requirements are groundless. For instance, SCE presents the straw-man argument that the guidelines could require deployment of CRCs throughout its service area, at no more than 30 minutes driving distance from every single customer.[25] This claim is contradicted by the letter and intent of the Staff Proposal. The purpose of CRCs is to protect the public and mitigate the impact of PSPS outages. The IOUs have detailed climate and system information that allows them to identify the specific lines and circuits that have a meaningful probability of losing power during a PSPS event. CRCs are only needed in the areas supplied by these "PSPS-risk" lines and circuits, areas that, in sum, constitute only a fraction of each IOU's service territory.

SCE further requests that the Commission allow the IOUs to make "reasonable exceptions to the 30-minute driving rule" suggesting that the IOUs shouldn't be required to set up CRCs for small numbers of customers that reside in remote locations.[26] This request should be rejected. The IOUs duty to provide electric service and to mitigate the impacts of PSPS events applies to small rural

---

[25] SCE Opening Comments at 12.
[26] SCE Opening Comments at 13.

communities just as much as it applies to large urban ones. Further, arranging CRCs for even small, isolated communities is not an undue burden for the utilities. Smaller communities have smaller populations. Serving small rural communities will require significantly more CRCs, but these CRCs can be significantly smaller than CRCs that serve dense urban populations. The number of CRCs needed to cover rural areas is counterbalanced by the smaller size (and lower cost) of these CRCs.

E. Restoration of Power Service Upon Conclusion of PSPS Event

CalCCA supports the Staff Proposal's 24-hour power restoration proposal, and ask that the Commission disregard IOU opposition to this proposal. As currently worded, the proposal is not a set-in-stone mandate, but rather a reporting requirement. The proposal allows ample room for the IOUs to exceed the 24-hour period if safety, physical conditions, or other reasonable circumstances dictate. The proposal only requires that the IOU document the fact that the time limit was exceeded and demonstrate that there was a reasonable basis for exceeding the limit. This is not an undue burden, and any additional operational pressure that the requirement places on the IOUs is far outweighed by the impact experienced by the public as the result of even an hour of unnecessary delay in power restoration.

F. Transportation Resilience

CalCCA does not have comments on this subject at this time.

G. Medical Baseline and Access and Functional Needs Populations

i. AFN Evacuation Plan

CalCCA agrees with the Joint Local Governments' concerns regarding the feasibility of developing or implementing a comprehensive evacuation plan for all AFN individuals within likely PSPS-impact areas.[27] These concerns highlight the need for a separate "life support" designation and the identification of all life support customers, as proposed by CalCCA in its opening comments.[28] While it is clear that some evacuations are necessary prior to PSPS events, the most important population to evacuate consists of AFN individuals that rely on electrically powered equipment for life support. Developing a plan to identify and evacuate these critically vulnerable individuals should be significantly less burdensome than developing a broad evacuation plan for all AFN

---

[27] Joint Local Governments Opening Comments at 19.

[28] CalCCA Opening Comments at 22.

individuals, and will ensure that limited evacuation resources are targeted to those at the greatest risk during a PSPS outage.

ii. Needs Assessment

CalCCA strongly agrees with TURN that that the IOUs should be required to aggressively expand MB enrollment.[29] As proposed in CalCCA's opening comments, the IOUs should be subject to mandatory deadlines for identifying and enrolling currently unenrolled MB-eligible customers. SCE's objections to the Staff Proposal's 60-day window for developing a plan should be disregarded. The IOUs should have been engaged in this type of planning for months now, and in many cases should be able to leverage the significant work in this area already performed by local HHS and AFN coordinators in response to federal requirements.

CalCCA supports CforAT's proposal that the IOUs focus their AFN identification efforts on those AFN individuals that are identifiable using information already in the IOUs' customer databases.[30] This "low hanging fruit" can be implemented immediately and without raising any privacy questions, while providing time for the Commission to give more deliberate consideration to the more complex public safety and AFN individual privacy considerations raised by expanding IOU-held AFN lists.

H. Transparency

CalCCA does not have comments on this subject at this time.

I. Definitions

CalCCA does not have comments on this subject at this time.

/ / /

29 TURN Opening Comments at 7.
30 CforAT Opening Comments at 11-13.

II. CONCLUSION

CalCCA thanks the Commission for its consideration of these reply comments.

Respectfully Submitted,

/s/ David Peffer

David Peffer
BRAUN BLAISING SMITH WYNNE P.C.
555 Capitol Mall, Suite 570
Sacramento, CA 95814
Tel: (916) 326-5812
E-mail: peffer@braunlegal.com

February 26, 2020

February 3, 2020

CA Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Advice Letter 40-E

Re: Rebates that Exceed Measure Costs in MCE's 2020 Annual Budget Advice Letter

Pursuant to the disposition letter ("Disposition") of Marin Clean Energy's ("MCE") 2020 Annual Budget Advice Letter[1] ("2020 ABAL") from December 20, 2019, MCE hereby provides the rationale for including rebates that exceed measure costs under the 2020 ABAL.

Tier Designation

This Advice Letter ("AL") has a Tier 1 designation pursuant to the Disposition of the 2020 ABAL.

Effective Date

Pursuant to General Order 96-B, MCE respectfully requests that this Tier 1 AL become effective by February 4, 2020.

Background

MCE filed the 2020 ABAL on September 3, 2019. On September 23, 2019, the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates") filed a protest of MCE's 2020 ABAL which included several recommendations regarding MCE's and other Program Administrators' ("PA") ABAL filings.

In its protest, Cal Advocates identifies several measure where rebates exceed the cost of the measure and argues that the forecasted rebate level and measure costs may contribute to an overly optimistic forecast of MCE's portfolio results.[2] The Disposition directed MCE make corrections to incentive and measure costs or provide a rationale for the rebate amount within 45 days.[3]

---

[1] MCE Advice Letter 37-E.

[2] Cal Advocates Protest at 39-40.

[3] See Disposition of MCE's ABAL at 7.

Purpose

The purpose of this advice letter filing is for MCE to provide a rationale for including rebates that exceed measure in the 2020 ABAL filing.

Rationale for Including Rebates that Exceed Measure Costs

The California Public Utilities Commission ("Commission") acknowledges "that there may be limited program design purposes where the cash rebate to the customer exceeds measure installation costs."[4] A primary justification for MCE's Strategic Energy Management ("SEM") programs is that they support the low- and no-cost measures and savings opportunities, where incentives are likely to exceed measure costs.

While the Total Resource Cost Test ("TRC") is the primary measure of energy efficiency portfolio cost-effectiveness, the Dual Test is the appropriate means to evaluate MCE's portfolio and address Cal Advocates' incentive concerns. California adopted the Dual Test in its policy rules to address these types of circumstances and to ensure that Program Administrators ("PAs") are not overspending on incentives to achieve overly optimistic TRC results.[5] If MCE proposed disproportionate incentive amounts, its portfolio would pass the TRC test, but fail the Program Administrator Cost ("PAC") test. MCE's 2020 portfolio passed both tests of cost-effectiveness.

Dual Cost-Effectiveness Test

The Commission allows for incentives to exceed measure costs where justified. In such instances, the TRC and the PAC tests are applied together as the Dual Test.[6] This is because incentives are not explicitly accounted for in the TRC calculation. The TRC test compares the benefits to society as a whole with the participant's cost of installing the measure plus the cost of energy efficiency program administration (non-incentive costs).[7] The PAC test compares the PA's avoided cost benefits with energy efficiency expenditures (incentives plus administrative costs).[8] In other words, the PAC should be evaluated along with the TRC because the primary purpose of the PAC test in such instances is to ensure that customer incentives are limited while not radically altering the results of the TRC test with high net benefits.[9] MCE's 2020 portfolio meets the additional Dual Test requirement to ensure incentives will not be disproportionately spent within its portfolio.

---

[4] See D.06-06-063 at 72.

[5] See D.06-06-063 at 72.

[6] See Energy Efficiency Policy Manual at 18.

[7] See California Standard Practice Manual at 23.

[8] See California Standard Practice Manual at 23.

[9] See D.06-06-063 at 72.

Strategic Energy Management Overview

MCE's SEM offering is expected to have low measure costs with high savings and reasonable incentives. MCE includes a cohort-style SEM offering in its nonresidential program portfolio, consisting of a holistic, whole facility approach that leverages pre- and post-participation energy model comparisons to measures savings. SEM engagement in California requires a two-year customer commitment, which involves training workshops, facility audits, data-sharing, and measurement and verification activities.[10]

While capital projects may be identified and completed over the course of a SEM engagement, traditional custom or deemed energy efficiency projects are treated separately and are excluded from the SEM energy models. Conversely, MCE's SEM is specifically focused on low- or no-cost projects, in the identification of behavioral, retro-commissioning or operational ("BRO") opportunities.

These opportunities are identified in close collaboration with participants, and are documented in the Opportunity Register which is developed for each participant, per the California Industrial SEM Design Guide.[11] Level of effort within an Opportunity Register is documented in a consistent manner, assigning rankings to measures, used in conjunction with an associated estimate of hours and capital costs required to complete the recommendations to estimate projects costs. In short, measure costs are significantly lower under SEM programs than they are under custom, deemed, or upstream programs, since there may be no equipment purchase associated with a measure at all.

For the reasons aforementioned, MCE believes that SEM and other program designs focused on realizing low-cost savings opportunities that may otherwise be stranded represent the type of exception that the CPUC had in mind in D.06-06-063.

Conclusion

MCE respectfully provides the rationale for including rebates that exceed measure costs under its 2020 ABAL.

Notice

A copy of this AL is being served on the official Commission service lists for Rulemaking R.13-11-005.

For changes to these service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

---

[10] See California Industrial SEM Design Guide at 4.

[11] See California Industrial SEM Design Guide at 66.

Protests

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address as above).

In addition, protests and all other correspondence regarding this AL should also be sent by letter and transmitted electronically to the attention of:

Jana Kopyciok-Lande
Senior Policy Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Ave.
San Rafael, CA 94901
Phone: (415) 464-6044
Facsimile: (415) 459-8095
jkopyciok-lande@mceCleanEnergy.org

Alice Havenar-Daughton
Director of Customer Programs
MARIN CLEAN ENERGY
1125 Tamalpais Ave.
San Rafael, CA 94901
Phone: (415) 464-6030
Facsimile: (415) 459-8095
ahavenar-daughton@mceCleanEnergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

Correspondence

For questions, please contact Jana Kopyciok-Lande at (415) 464-6044 or by electronic mail at jkopyciok-lande@mceCleanEnergy.org.

/s/ Jana Kopyciok-Lande

Jana Kopyciok-Lande
Senior Policy Analyst
MARIN CLEAN ENERGY

cc: Service List: R.13-11-005

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy

Utility type:

- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Jana Kopyciok-Lande
Phone #: (415) 464-6044
E-mail: jkopyciok-lande@mcecleanenergy.org
E-mail Disposition Notice to: jkopyciok-lande@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE

ELC = Electric	GAS = Gas	WATER = Water
PLC = Pipeline	HEAT = Heat	

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 40-E

Tier Designation: 1

Subject of AL: To provide a rationale for including rebates that exceed measure costs in the 2020 ABAL filing.

Keywords (choose from CPUC listing):

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
N/A

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information: N/A
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 2/4/20

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division Attention: Tariff Unit 505 Van Ness Avenue San Francisco, CA 94102 Email: EDTariffUnit@cpuc.ca.gov	Name: Jana Kopyciok-Lande Title: Senior Policy Counsel Utility Name: Marin Clean Energy Address: 1125 Tamalpais Ave City: San Rafael State: California Zip: 94901 Telephone (xxx) xxx-xxxx: 415-464-6044 Facsimile (xxx) xxx-xxxx: 415-459-8095 Email: jkopyciok-lande@mcecleanenergy.org
	Name: Alice Havenar-Daughton Title: Director of Customer Programs Utility Name: Marin Clean Energy Address: 1125 Tamalpais Ave City: San Rafael State: California Zip: 94901 Telephone (xxx) xxx-xxxx: 415-464-6030 Facsimile (xxx) xxx-xxxx: 415-459-8095 Email: ahavenar-daughton@mceCleanEnergy.org

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

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

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

MARIN CLEAN ENERGY 2020 ANNUAL BUDGET ADVICE LETTER WORKSHOP REPORT

Jana Kopyciok-Lande
Senior Policy Analyst
MCE Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6044
Facsimile: (415) 459-8095
E-Mail: jkopyciok-lande@mcecleanenergy.org

February 18, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

MARIN CLEAN ENERGY 2020 ANNUAL BUDGET ADVICE LETTER WORKSHOP REPORT

Pursuant to the California Public Utilities Commission's (CPUC or Commission) order in decision D.18-05-041, MCE hereby submits its 2020 Energy Efficiency Annual Budget Advice Letter (ABAL) Workshop Report which summarizes the workshop held on February 3, 2020. The report includes MCE's proposal for meeting/exceeding a 1.0 total resource cost (TRC) on an evaluated basis and transitioning to a TRC forecast of 1.25 during the ramp years, and includes stakeholder comments from the workshop. The ABAL workshop report is provided as Attachment A. MCE looks forward to receiving stakeholder feedback on MCE's 2020 ABAL workshop report, and to further developing and improving its portfolio.

Respectfully submitted,

/s/ Jana Kopyciok-Lande

Jana Kopyciok-Lande
Senior Policy Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Ave
San Rafael, CA 94901
Tel: (415) 464-6044
E-mail: jkopyciok-lande@mceCleanEnergy.org

February 18, 2020

Attachment A

MCE's 2020 Energy Efficiency

Annual Budget Advice Letter Workshop Report

MCE 2020 Energy Efficiency Annual Budget Advice Letter Workshop Report

February 18, 2020

Table of Contents

MCE's 2020 Energy Efficiency Annual Budget Advice Letter Workshop Report

Introduction

On May 31, 2018, the California Public Utilities Commission (Commission) issued D. 18-05-041 requiring Program Administrators (PAs) to hold a workshop if their Energy Efficiency Annual Budget Advice Letter (ABAL) filing proposes a portfolio forecast Total Resource Cost (TRC) that meets or exceeds 1.0 but does not meet or exceed 1.25.[1] On September 3, 2019 MCE submitted its 2020 ABAL (Advice Letter 37-E), as required by D.15-10-028 and D.18-05-041.

On December 20, 2019, the CPUC approved MCE's 2020 ABAL, which included a forecasted portfolio TRC of 1.01. Because the forecasted TRC in the ABAL is less than 1.25, MCE held an ABAL workshop. In compliance with D.18-05-041, MCE took the following actions related to the ABAL workshop:

- On January 3, 2020 – MCE issued a "Notice of MCE's 2020 Annual Budget Advice Letter workshop" to the service lists for the EE Rulemaking R.13-11-005;[2] and
- February 3, 2020 – MCE held its 2020 EE ABAL Workshop at its Concord office, 2300 Clayton Rd 11th Floor Suite 1150.[3]

Pursuant to D.18-05-041, this report summarizes MCE's 2020 EE ABAL workshop and includes MCE's proposal for meeting or exceeding a 1.0 TRC on an evaluated basis and transitioning to a TRC forecast of 1.25 during the ramp years. The report also includes a list of attendees and summary of stakeholder comments and questions from the ABAL workshop.[4]

---

[1] See D.18-05-041 at 135

[2] See D.18-05-041 at 135, requires that the PA must provide notice of the workshop to service list R.13-11-005 or its successor, no later than 30 days prior to the workshop date.

[3] See D.18-05-041 at 135, requires that within 45 days after staff's approval of its ABAL, the PA must hold a workshop.

[4] See D.18-05-041 at 135-136, requires that within 15 days after the workshop, the PA must produce a report summarizing the workshop, including the PA's proposal for meeting/exceeding a 1.0 TRC on an evaluated basis and transitioning to a TRC forecast of 1.25 during the ramp years, and stakeholder comments from the workshop.

Workshop Summary

On February 3, 2020, MCE held its required 2020 ABAL workshop at its Concord office. The workshop was attended by stakeholders in-person and via webinar.

MCE presented slides, including an overview of MCE's 2020 ABAL, cost-effectiveness challenges and strategies, program ideas, and responded to stakeholders' questions. A summary of MCE's presentation at the workshop, which included MCE's proposal to achieve a TRC of 1.0 on an evaluated basis and its plan to transition to a TRC forecast of 1.25 during the ramp years is provided in the sections below. A copy of MCE's 2020 EE ABAL workshop presentation is in Appendix A of this report.

Strategies for Meeting a 1.0 TRC on an Evaluated Basis

MCE's proposal for meeting a 1.0 TRC on an evaluated basis for the 2020 program year includes coordinating with partner programs such as BayREN to fill in the gaps by offering energy efficiency measures and programs without limiting opportunities to our customers, deploying measure cost savings strategies such as Strategic Energy Management (SEM) and Behavioral, Retro commissioning, and Operational (BROs) components, using NMEC and performance-based payment structures, and leveraging our Advanced Metering Infrastructure (AMI) platform to target customers to maximize savings and generate realistic avoided cost benefits.

Transition Plan to a Portfolio with a TRC Forecast of 1.25 During the Ramp Years

MCE plans to improve its TRC as it progresses through the Business Plan period by using its AMI platform to perform backcast analysis to understand program and project performance as well as inform future program and portfolio optimization. MCE will modify its portfolio when there are updates to Database for Energy Efficiency Resources (DEER) and Workpaper dispositions that change cost-effectiveness values. Finally, MCE is expecting significant cost-effective savings from several programs launched in the second half of 2019.

Stakeholder Comments

At the conclusion of the presentation, MCE sought questions from workshop stakeholders. Below is a list of questions received and MCE's responses.

Question: The admin cost percentage is 10.42% of the portfolio budget. Are you going to try to take admin down to 10%?

The list of activities MCE charges to the admin cost category is directly from the EE policy manual and that is what we use to allocate expenses. Yes, we are going to work to bring down our admin costs as much as we can to bring it at or below 10 percent.

Question: Electrification or fuel substitution is listed as a program idea. Are there studies to show that it's cost effective?

The list of program ideas come directly from our Business Plan. Our Business Plan was written a while ago and many things have changed since then. However, we are tracking the development of fuel substitution workpapers.

Stakeholder Attendance

In-Person

Last Name	First Name	Email Address
Havenar-Daughton	Alice	ahavenar-daughton@mcecleanenergy.org
Vallery	Qua	qvallery@mcecleanenergy.org
Kreutzer	Jenn	jkreutzer@mcecleanenergy.org
Strindberg	Nils	nils.strindberg@cpuc.ca.gov
Buck	Charlie	charlie.buck@oracle.com
Peralta	Grace	gperalta@mcecleanenergy.org
Greene	Jennifer	jgreene@mcecleanenergy.org

Via Zoom Conference

Last Name	First Name	Email
Schmidt	Lisa	lisa@hea.com
Kopyciok-Lande	Jana	jkopyciod-lande@mcecleanenergy.org
Petrofsky	Erica	epf@cpuc.ca.gov
Babka	Sophie	sophie.babka@cpuc.ca.gov

Torok	Christie	christina.torok@cpuc.ca.gov
Lande	Joseph	jlande@mcecleanenergy.org
O'Neill	Joanne	joanne.oneill@clearesult.com
Clevinger	Amanda	aclevinger@brightpower.com
Rodriguez	Kimberly	krodriguez@nexant.com
Khursheed	Aaiysha	akhursheed@opiniondynamics.com
Johnston	Brian	bjohnston@semprautilities.com
Franzese	Peter	peter.franzese@cpuc.ca.gov
Warta	Greg	gwarta@bidgely.com
Wong	Aimee	aimee.wong@sce.com
Siddiqui	David	david.siddiqui@oracle.com
Dewey	Meghan	megdewey@gmail.com
Terry	Patricia	pterry@redwoodenergy.org
Rudolph	Coby	coby.rudolph@cpuc.ca.gov

Next Steps

Pursuant to D.18-05-041, parties may file comments on MCE 2020 EE ABAL workshop report within 20 days. MCE will review stakeholders' feedback and develop a draft framework or proposal for making portfolio improvements to ensure the portfolio is on track to meet the ABAL review criteria in future program years.

Appendix A

MCE's 2020 Energy Efficiency

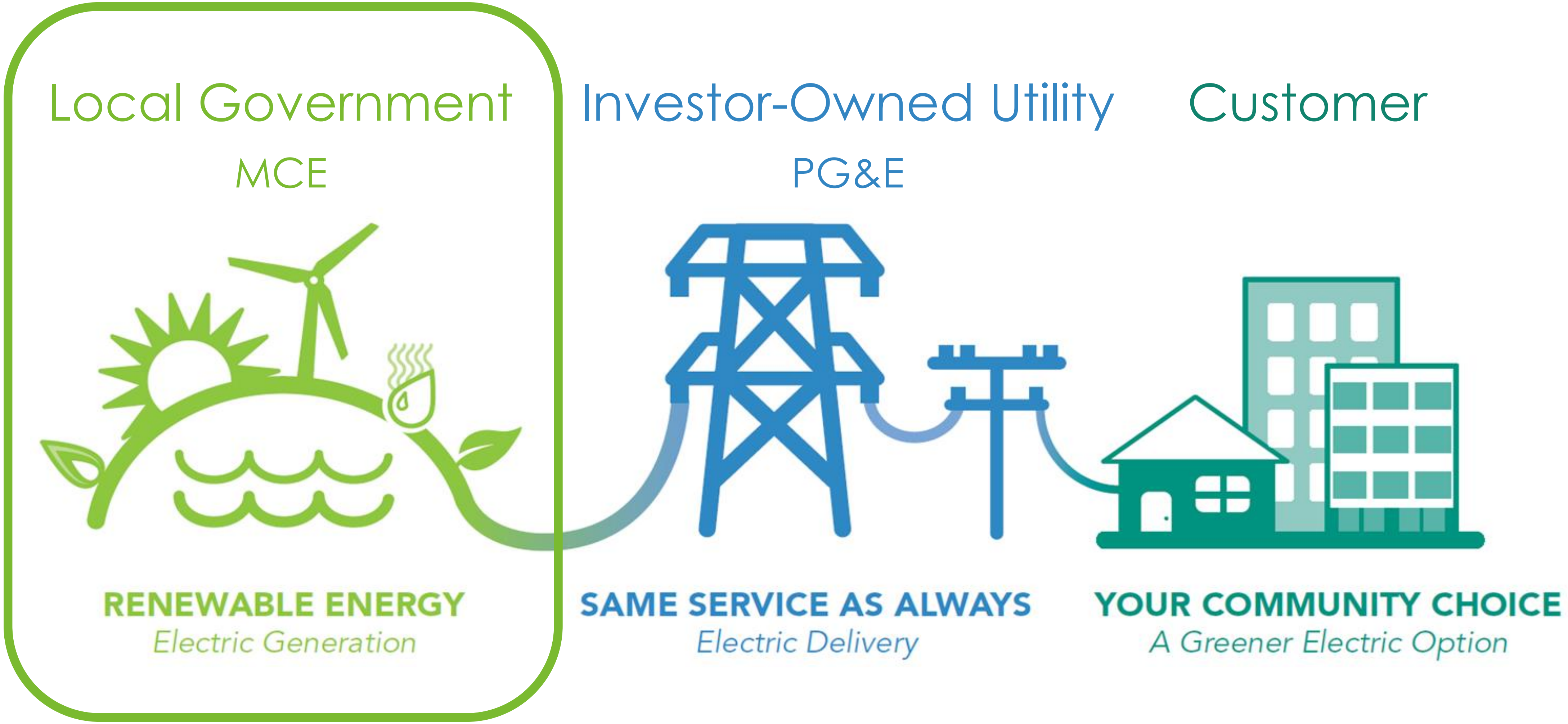
Annual Budget Advice Letter Workshop Presentation

MCE 2020 ABAL Workshop

February 3, 2020

Workshop Overview

1. MCE Background
2. 2020 Portfolio Overview
3. 2020 Budget and Cost-Effectiveness Overview
4. Admin Costs and Accounting Practices
5. Ex-Ante vs Ex-Post TRC
6. Forecasted vs Claimed Savings
7. 2020 Cost-Effectiveness Challenges, Strategies, and Safeguards
8. AMI Analytics Platform Scenarios
9. Cost-Effectiveness Strategies to Achieve TRC of 1.25 by 2023
10. 2021 and Beyond Program Ideas
11. Stakeholder Input


Local Government
MCE
Investor-Owned Utility
PG&E
Customer
RENEWABLE ENERGY
Electric Generation
SAME SERVICE AS ALWAYS
Electric Delivery
YOUR COMMUNITY CHOICE
A Greener Electric Option

How It Works

Our Mission

Address climate change by reducing energy related greenhouse gas emissions through renewable energy supply and energy efficiency at stable and competitive rates while providing local economic and workforce benefits.

Emphasis on Customer Experience

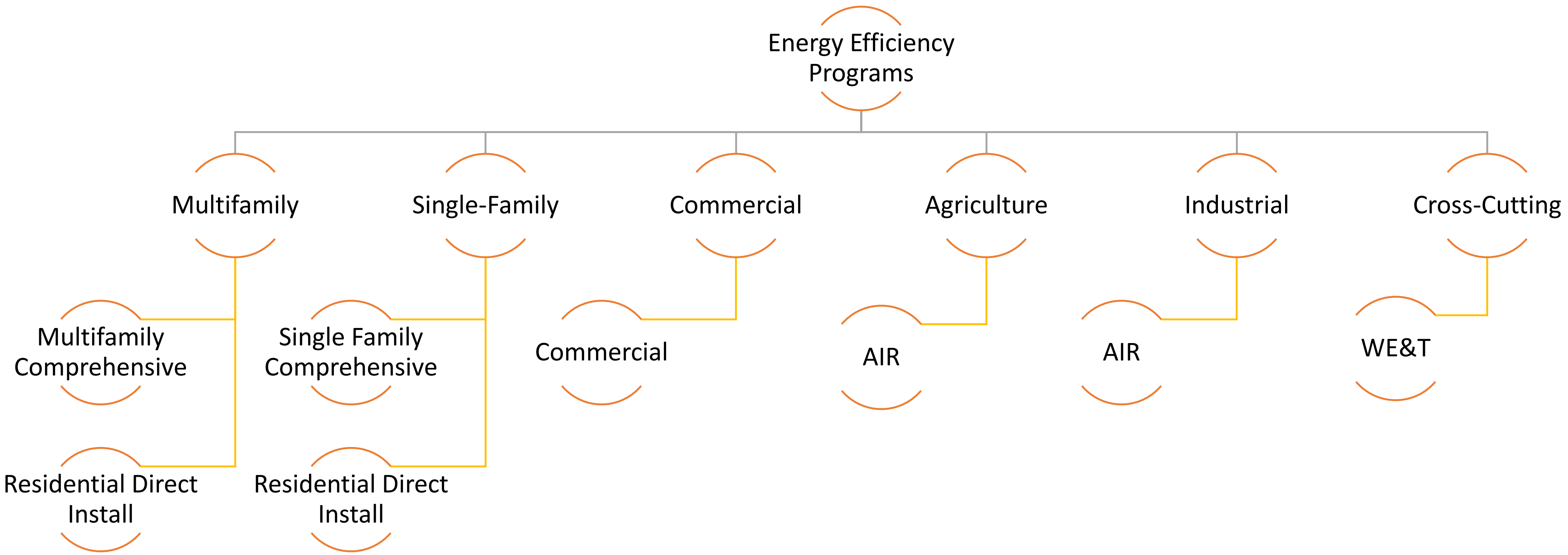
Putting customers on a path that serves all their conservation needs through one point of entry

Single Point of Contact (SPOC)

2020 Portfolio

Overview

MCE's Energy Efficiency Programs



Residential

Programs

Multifamily Energy Savings Program

(MCE01)

- All of MCE service area
- Multifamily properties (4+ Units)
- Multifamily property owners and residents
- Technical assistance, single-measure cash rebates and direct install

Residential Direct Install Program

(MCE05 & MCE08)

- All of MCE service area
- Single family and multifamily owners and renters
- Customers in DACs and households with income between 80 and 120% AMI
- Initial energy assessment and no-cost direct install measures

Residential Comprehensive

(MCE07)

- Available to both single family renters and owners
- Pay-for-Performance contracting
- Meter based savings
- Digital or paper Home Energy Reports sent at strategic billing cycle points
- Web portal with energy saving recommendations
  - Similar homes comparison
  - Budgeting reminders
  - Recommended energy-saving and upgrades
- Behavior program using NMEC savings calculation with RCT participant and control group selection

Seasonal Savings (MCE03)

- Currently evaluating if program will be feasible with new implementation partner

WE&T

(MCE16)

- Currently developing program with new implementation partner

Non-Residential Programs

Commercial Program

- All of MCE Territory
- Any Commercial Property
- Commercial Owners and/or Tenants
- Technical Assistance & Energy Savings Upgrades

Commercial Program

- Comprehensive program design
- Hard-to-reach component
- Multiple participation pathways
- Technical assistance
- Financing support
- Cash rebates

MCE Agricultural & Industrial Resource (AIR) Program

- All of MCE Territory
- Industrial or Agricultural Facility
- Agricultural or Industrial Owners and/or Tenants
- Technical Assistance & Energy Savings Upgrades

AIR Program

- Comprehensive site assessments
- Multiple participation pathways
  - Deemed
  - Calculated
  - Meter-based
  - Strategic Energy Management (SEM)
- Project management and procurement support
- Cash rebates

Strategic Energy Management (SEM)

- 2 year commitment
- One-on-one energy coaching
- Quarterly workshops and trainings
- Treasure hunt & organizational assessments
- Model based energy savings
- Cash rebates for milestones and achieved savings

Budgets, Cost-Effectiveness & Accounting

2020 Budget and Cost-Effectiveness

Sector	Budget	Annual Net kW	Annual Net kWh	Annual Net Therms
Agricultural	$687,463	224	1,040,037	24,882
Commercial	$1,477,001	524	3,164,164	19,978
Industrial	$2,125,484	380	2,150,599	268,485
Residential	$2,163,109	660	5,087,595	239,309
WE&T	$346,667	NA	NA	NA
EM&V	$108,796	NA	NA	NA
Portfolio Total	$6,908,519	1,628	11,442,395	552,654
Portfolio TRC	1.01			
Portfolio PAC	1.05			

Admin. Costs and Accounting Practices

Sector	Admin	Percent Admin
Agricultural	$85,171	1.2%
Commercial	$142,835	2.1%
Industrial	$278,490	4.0%
Residential	$213,503	3.1%
Portfolio Total	$720,000	10.42%

Admin. Costs and Accounting Practices

Admin Costs – Overhead and GA
Accounting support
IT services and support
Reporting databases
Data request responses
CPUC financial audits
Regulatory filing support
Travel and conference fees
Membership dues
Facility related cost
Supply management fuction activities to ensure oversight of contractors
Administering contractor payments for services with are non-incentive related
Admin and logistical costs related to workshops on Strategic Planning issues

Ex-Ante vs. Ex-Post TRC

Program	Program Year	Ex Ante TRC	Ex Post TRC
Multifamily	2014	0.25	0.25
Small Commercial	2014	1.52	1.15

- One impact evaluation performed on MCE's portfolio
- Reported vs. Evaluated TRCs by program

Forecasted vs. Claimed Savings

Program Year	Forecasted Net kW	Claimed Net kW	Percent kW Goal	Forecasted Net kWh Savings	Claimed Net kWh Savings	Percent kWh Goal	Forecasted Net Therms Savings	Claimed Net Therms Savings	Percent Therms Goal
2016	NA	87	NA	NA	731,077	NA	NA	8,124	NA
2017	351	223	64%	1,812,755	1,262,243	70%	33,850	34,821	103%
2018	349	153	44%	1,846,948	1,159,591	63%	70,289	70,381	100%
2019*	592	221	37%	5,852,476	1,107,712	19%	403,832	3,859	1%

- 2019 savings as of December 2019

2020 Cost-Effectiveness Challenges

- TRC contradicts consumer preferences
- Significantly more efficient baselines with higher savings targets
- Limited cost-effective deemed offerings
- DEER updates and workpaper dispositions that change cost-effectiveness values
  - Results in misalignment between projections and claimed savings
- Short cost-effectiveness measurement timeframe
  - Time needed to transition portfolio from non-CE to CE
  - Handling transitions in programs

2020 Cost-Effectiveness Strategies

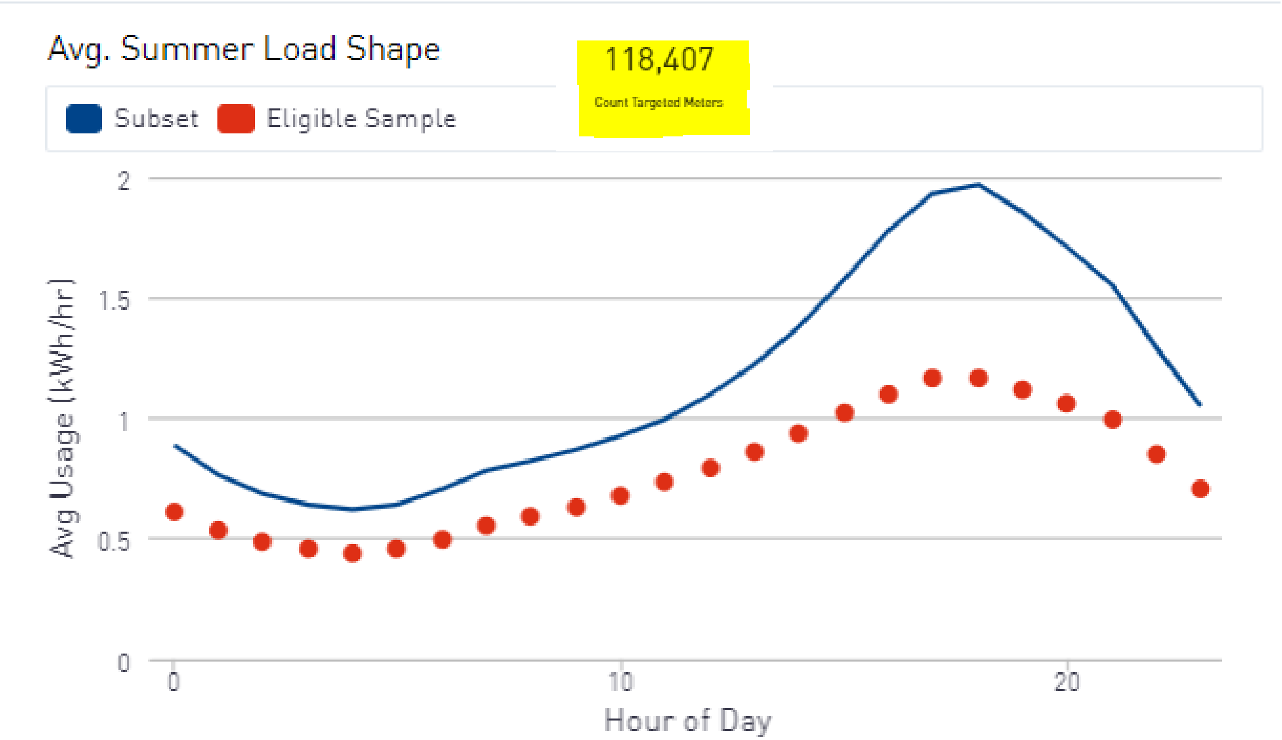
- Improved program coordination and referral systems with other partner programs to improve CE without limiting opportunities for our customers
- Deploy measure cost savings strategies
  - Strategic Energy Management (SEM)
  - Behavioral, Retro commissioning, and Operational (BROs)
- NMEC and performance-based payment structures
- Use of AMI analytics platform
  - Individual site-level profiles for every building in MCE's service territory to pre-screen applicants, target customers, and maximize savings
  - Population-wide energy use patterns to generate realistic savings potential and assess proposed program designs
  - Load shape analysis

2020 Cost-Effectiveness Safeguards

- Meter-based savings
- Performance-based implementation contracts

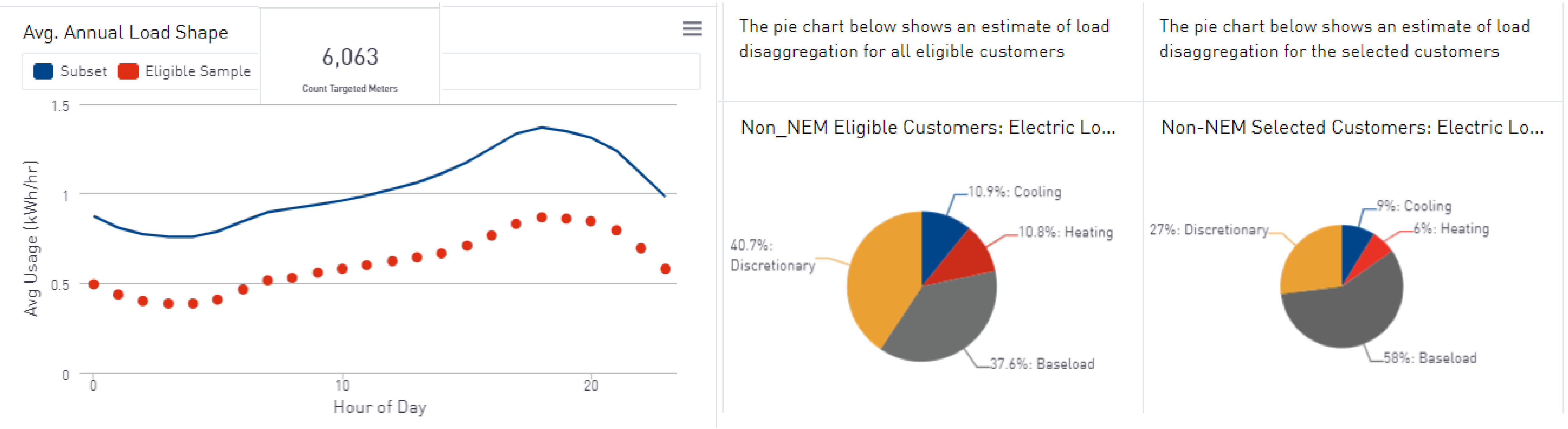
AMI Analytics Platform Scenarios

- Red dotted line: Average customer load shape for all Residential customers in MCE's service territory without solar during Summer
- Solid Blue Line: Top 50% of customers who have a high summer usage and high usage during the evening ramp (6-7 PM)



AMI Analytics Platform Scenarios

- Red dotted line: Annual Average Residential CARE customer load shape in MCE's service territory without solar
- Solid Blue Line: Top 7.5 percent of CARE customers with the highest annual baseload usage



Cost Effectiveness Strategies to Achieve 1.25 TRC by 2023

- Continual program optimization
  - Backcast Analysis
- Improving MCE's visibility into upcoming measure changes to deemed measures and workpapers
- Expected savings in 2020 and 2021 from program ramp-up activities from the 2018 and 2019 transition years
  - AIR
  - SF + MF DI
  - SF Comprehensive

2021 Program Ideas and Beyond

- Expanded workforce development
  - Leveraging existing EE programs to layer EE workforce development
  - Leverage existing WE&T training to augment offerings/services for EE workforce
- Fuel Substitution
- Expanded SEM participation
- Zero Net Energy (ZNE)
- New construction
- Data analytics and behavior approaches/programs
- Normalized Metered Energy Consumption
- Third-party partnerships

Stakeholder Input

Other program ideas?

Next Steps

Next Steps

- 2020 ABAL Workshop Report – 02/18/2020
- Comment Period Deadline – 03/09/2020
- MCE Review Stakeholder Feedback

Thank You

Alice Havenar-Daughton

Director of Customer Programs

ahavenar-daughton@mcecleanenergy.org

Qua Vallery

Customer Programs Specialist

qvallery@mcecleanenergy.org

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 Filed February 11, 2016

MARIN CLEAN ENERGY'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING ALLOWING UPDATED INTEGRATED RESOURCE PLANNING LOAD FORECASTS

Nathaniel Malcolm
Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6048
Facsimile: (415) 459-8095

February 28, 2020

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

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 Filed February 11, 2016

**MARIN CLEAN ENERGY'S COMMENTS ON
ADMINISTRATIVE LAW JUDGE'S RULING ALLOWING
UPDATED INTEGRATED RESOURCE PLANNING LOAD FORECASTS**

Pursuant to the January 24, 2020 *Administrative Law Judge's Ruling Allowing Updated Load Forecasts* ("ALJ Ruling") issued in the instant proceeding, Rulemaking ("R.")16-02-007, Marin Clean Energy ("MCE") submits the following Integrated Resource Planning ("IRP") load forecast update. Pursuant to a January 31, 2020 email from Administrative Law Judge ("ALJ") Fitch responding to parties' requests for extension to file comments, the filing deadline for comments on the ALJ Ruling was extended to February 28, 2020. As such, these comments are timely filed.

I. INTRODUCTION

The Updated MCE Forecast includes two adjustments to the California Energy Commission's ("CEC") 2019 Integrated Energy Policy Report ("IEPR") forecast for MCE:

1. The Updated MCE Forecast reduces MCE's projected load to account for expected load migration from MCE to Direct Access ("DA") service in the years 2021-2030.
2. The Updated Forecast adjusts MCE's projected load to use more accurate LSE-specific projections regarding the load impact of MCE's planned 2021 expansion into the cities of Vallejo and Pleasant Hill ("2021 Expansion").

The specific forecast adjustments for these factors are set forth in Attachment A. MCE requests it be able to use the MCE Updated Load Forecast in Attachment A for IRP purposes.

II. MCE'S LOAD FORECAST SHOULD BE UPDATED TO ACCOUNT FOR EXPECTED LOAD DEPARTURE TO DIRECT ACCESS SERVICE

MCE respectfully requests that the Commission adjust its load forecast for the years 2021-2030 to account for 60 GWh/year[1] in projected departure from MCE service due to DA program expansion. This adjustment is reflected in Attachment A to this filing. In order to ensure that all LSE load forecasts add up to the IEPR total load forecast, MCE requests that its reduction of 60 GWh/year be balanced by a corresponding addition of 60 GWh/year to DA providers.

III. MCE'S LOAD FORECAST SHOULD BE UPDATED TO ACCURATELY REFLECT THE LOAD IMPACT OF MCE'S 2021 EXPANSION TO THE CITIES OF VALLEJO AND PLEASANT HILL

MCE respectfully requests that its load forecast be adjusted to use its own, more accurate, LSE-specific projections regarding the load impact of its planned 2021 Expansion. These adjustments are set forth in Attachment A. In order to ensure that all LSE load forecasts add up to the IEPR total load forecast, MCE requests that its requested load forecast reductions be counterbalanced by adding the same amount to the PG&E bundled service load forecast. These requested forecast adjustments are reflected in Attachment A.

---

[1] MCE's DA departure projection is based, in part, on aggregated data provided by PG&E regarding the amount of MCE customer load that has signed up for DA service. Although this data was provided in aggregate form and does not include identifying customer information, out of an abundance of caution, and to avoid overstating potential load departure, MCE is providing its own DA departure projection that is somewhat lower than that provided by PG&E.

In 2021 MCE will be expanding its service territory to include the cities of Vallejo and Pleasant Hill. MCE notified the Commission of this expansion and projected the additional load associated with this expansion in its December 6, 2019, *Marin Clean Energy Addendum No. 7 to the Revised Community Choice Aggregation Implementation Plan and Statement of Intent to Address MCE Expansion to the Cities of Vallejo and Pleasant Hill* ("Implementation Plan"). MCE's Implementation Plan projections utilized historical monthly usage data for all bundled service customers in the new communities, adjusted for an assumed opt-out rate of 10%. The projections reflected the planned enrollment of these new customers during the month of April, 2021.

MCE's 2021 Expansion is reflected in Table 1, below. Table 1 shows the "MCE Original Forecast" provided to the CEC in April 2019. The "MCE Original Forecast" is then adjusted upward to account to MCE's 2021 Expansion into Pleasant Hill and Vallejo, resulting in the "MCE Forecast with 2021 Expansion".

TABLE 1: MCE's Forecast Adjustments To Account For MCE's 2021 Expansion

Year	MCE Original Forecast (GWh)	Projected Pleasant Hill and Vallejo Load (GWh)	MCE Forecast with 2021 Expansion (GWh)[2]
2020	5,094	0	5,094
2021	5,221	329	5,550
2022	5,266	463	5,729
2023	5,256	462	5,718
2024	5,251	462	5,713
2025	5,251	462	5,713
2026	5,259	462	5,721
2027	5,266	463	5,729
2028	5,291	465	5,756
2029	5,412	476	5,888
2030	5,558	489	6,047

2 The "MCE's Forecast with 2021 Expansion" does not include an adjustment for expected DA departure.

Notably, however, the CEC's 2019 IEPR forecast (*CED 2019 Managed Forecast – LSE and BA Tables Mid Demand – Mid AAEE Case – CORRECTED 11c,* issued January 22, 2020) for MCE varies *materially* from MCE's adjusted "MCE Forecast with 2021 Expansion". This discrepancy between the 2019 IEPR and "MCE Forecast with 2021 Expansion" is shown in Table 2, below.

TABLE 2: Comparison of MCE Forecast with 2021 Expansion and Final 2019 IEPR Forecast

Year	MCE Forecast with 2021 Expansion (GWh)	Final 2019 IEPR Forecast (GWh)[3]	Difference (GWh)
2020	5,094	5,498	-404
2021	5,550	5,879	-329
2022	5,729	6,039	-310
2023	5,718	6,028	-310
2024	5,713	6,036	-323
2025	5,713	6,044	-331
2026	5,721	6,049	-328
2027	5,729	6,049	-320
2028	5,756	6,052	-296
2029	5,888	6,050	-162
2030	6,047	6,053	-6

Given that the "MCE Forecast with 2021 Expansion" reflects MCE's LSE-specific projections regarding the load impact of MCE's 2021 Expansion, MCE requests that its IEPR forecast be adjusted downward by the "Difference" in Table 2 for years 2020-2030. This downward adjustment is included in MCE's Updated Load Forecast provided in Attachment A.

[3] Importantly, the CEC informed MCE that the final 2019 IEPR forecast for MCE included load growth assumptions for MCE based on analysis of MCE's December 6, 2019 Implementation Plan.

IV. THE COMMISSION SHOULD EXERCISE CAUTION WHEN CONSIDERING PROCUREMENT OR NON-BYPASSABLE CHARGES BASED ON THE 2019 IEPR LOAD FORECAST

While MCE appreciates the importance of IEPR and recognizes the tremendous effort that the CEC puts into the IEPR process, IEPR is not an ideal source for individual, LSE-specific load forecasts. The IEPR process is intended to provide a high-level analysis of the state's energy policy needs. IEPR is designed to provide accurate load projections at the macro-level (for regions, Investor-Owned Utility service territories, and the state as a whole), and is simply not equipped to provide accurate load projections at the individual LSE level. This is explicitly recognized in the ALJ Ruling, which states:

> Commission staff and CEC staff are aware that there are data collection, timing, and forecast accuracy issues associated with the handoff between the IEPR load forecast and the IRP process. Staff are in ongoing discussions to identify ways in which this interaction could be improved for future IRP cycles. These discussions are likely to lead to process changes which will be proposed and vetted in either the IEPR or this proceeding, as appropriate.[4]

The CEC's final load projection for MCE demonstrates MCE's concerns with making binding procurement decisions and allocating financial obligations such as non-bypassable charges and/or procurement obligations based on LSE-specific load forecasts taken from IEPR. For example, in 2021 the 329 GWh difference between MCE's projection and the IEPR projection is a material difference – this difference overestimates MCE's 2021 load by 6%, a figure equivalent to the load demand of a medium-sized city such as Walnut Creek.

Again, MCE appreciates the importance of the IEPR and IRP processes. This is why MCE puts forth significant efforts to ensure that its IRP process is properly informed

---

[4] ALJ Ruling at 2.

by the best load projections possible. MCE acknowledges that at this moment the Commission has settled on IEPR load projections for its LSE-specific load projections. However, given the problems associated with using IEPR for a purpose it was not designed for, and the extent of the difference between MCE's LSE-specific load forecast and the IEPR load forecast for MCE, the Commission should exercise caution when considering procurement mandates or non-bypassable charges in this IRP cycle and make developing an accurate and granular LSE-specific load projection methodology a top priority.

V. CONCLUSION

MCE thanks the Commission for its consideration of this request. For the reasons set forth above, MCE asks that the Commission adopt MCE's recommended load forecast adjustment provided in Attachment A.

Respectfully submitted by:

<u>/s/Nathaniel Malcolm</u>
Nathaniel Malcolm
Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6048
Facsimile: (415) 459-8095

Dated: February 28, 2020

ATTACHMENT A

MCE UPDATED LOAD FORECAST

ATTACHMENT A – MCE UPDATED LOAD FORECAST

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Final 2019 IEPR Load Forecast for MCE[1] (GWh)	5,498	5,897	6,039	6,028	6,036	6,044	6,049	6,049	6,052	6,050	6,053
Adjustment to Reduce 2019 IEPR Forecast of MCE's 2021 Expansion (To IOU Bundled) (GWh)	-404	-329	-310	-310	-323	-331	-328	-320	-296	-162	-6
MCE DA Departures (To ESP Service) (GWh)	0	- 60	- 60	- 60	- 60	-60	-60	-60	-60	-60	-60
Total Load Modification (GWh)	-464	-389	-370	-370	-383	-391	-388	-380	-356	-222	-66
MCE Updated Forecast (GWh)	5,034	5,490	5,669	5,658	5,653	5,653	5,661	5,669	5,696	5,828	5,987

[1] The CEC informed MCE that the final 2019 IEPR forecast for MCE included load growth assumptions for MCE based on analysis of MCE's December 6, 2019 Implementation Plan.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

FINAL REPORT OF WORKING GROUP 3 CO-CHAIRS: SOUTHERN CALIFORNIA EDISON COMPANY (U-338E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY

JANET S. COMBS
RUSSELL A. ARCHER
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, CA 91770
626.302.1524
Janet.Combs@sce.com

Attorneys for SOUTHERN CALIFORNIA EDISON COMPANY

EVELYN KAHL
ANN C. SPRINGGATE
BUCHALTER, A PROFESSIONAL CORPORATION
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
ekahl@buchalter.com

Counsel to CALIFORNIA COMMUNITY CHOICE ASSOCIATION

MICHAEL B. DAY
GOODIN, MACBRIDE, SQUERI & DAY, LLP
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
Email: mday@goodinmacbride.com

Attorneys for COMMERCIAL ENERGY OF CALIFORNIA

February 21, 2020

Final Report Of Working Group 3 Co-Chairs: Southern California Edison Company (U-338e), California Community Choice Association, And Commercial Energy

Table of Contents

Final Report Of Working Group 3 Co-Chairs: Southern California Edison Company (U-338e), California Community Choice Association, And Commercial Energy

Table of Contents

Section Page

Final Report Of Working Group 3 Co-Chairs: Southern California Edison Company (U-338e), California Community Choice Association, And Commercial Energy

Table of Contents

Final Report Of Working Group 3 Co-Chairs: Southern California Edison Company (U-338e), California Community Choice Association, And Commercial Energy

Table of Contents

Final Report Of Working Group 3 Co-Chairs: Southern California Edison Company (U-338e), California Community Choice Association, And Commercial Energy

Table of Contents

Final Report Of Working Group 3 Co-Chairs: Southern California Edison Company (U-338e), California Community Choice Association, And Commercial Energy

Table of Contents

Final Report Of Working Group 3 Co-Chairs: Southern California Edison Company (U-338e), California Community Choice Association, And Commercial Energy

Table of Contents

Section Page

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

FINAL REPORT OF WORKING GROUP 3 CO-CHAIRS: SOUTHERN CALIFORNIA EDISON COMPANY (U-338E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY

I.

INTRODUCTION

Pursuant to the Phase 2 Scoping Memo and Ruling of Assigned Commissioner, issued February 1, 2019 ("Phase 2 Scoping Memo"), Southern California Edison Company ("SCE"), on behalf of itself, California Community Choice Association ("CalCCA"), and Commercial Energy ("Commercial") (together, the "Co-Chairs"), respectfully files this final report on Working Group Three: Portfolio Optimization and Cost Reduction, and Allocation and Auction ("WG 3") (the "Final Report").[1]

II.

EXECUTIVE SUMMARY

Pursuant to the Phase 2 Scoping Memo of Rulemaking ("R.") 17-06-026, the WG 3 Co-Chairs are directed to address the following four issues relating to the treatment and management of excess resources in the investor-owned utilities' ("IOU") Power Charge Indifference

1 Pursuant to CPUC Rule 1.8(d), CalCCA and Commercial have authorized SCE to file this Final Report on their behalf.

Adjustment-eligible and Competition Transition Charge ("CTC")-eligible (collectively "PCIA") portfolios:

(1) Proposed new structures, processes, and rules governing portfolio optimization, and how these processes and rules should be structured so as to be compatible with other proceedings;

(2) Adoption of additional standards for more active management of IOU portfolios in response to departing load;

(3) How a transition to implement new standards should occur; and

(4) Whether new or modified IOU shareholder responsibility for portfolio mismanagement should be implemented.

After more than 10 months of dedicated work on the complex issues associated with portfolio optimization, the WG 3 Co-Chairs are pleased to file this Final Report to present the areas of consensus reached among the Co-Chairs. As discussed herein, the Co-Chairs' consensus proposals resolve a majority of the Phase 2 Scoping Memo's issues for WG 3. While the Co-Chairs' consensus proposals do not necessarily have the support of every party participating in WG 3, the Co-Chairs' consensus proposals represent thoughtful, reasonable and workable compromises among the Co-Chairs who, as Community Choice Aggregators ("CCA"), an Electric Service Provider ("ESP"), and an IOU, reflect the interests of a broad spectrum of the stakeholders in WG 3. The Co-Chairs jointly urge the California Public Utilities Commission ("CPUC" or "Commission") to adopt their consensus proposals and the implementation steps required to realize the Co-Chairs' consensus proposals, as set forth herein.

This Final Report also identifies areas of non-consensus among the Co-Chairs. The Final Report does not seek to advance the position of any party other than the Co-Chairs' consensus proposals. Parties' prior comments on proposals advanced by WG 3 in the First and Second Workshop presentations, and the Co-Chairs' response to parties' comments on the Second Workshop presentation, have been submitted with the First and Second Progress Reports of WG 3, and comments received from the Third and Fourth Workshops and in response to requests for proposals to address the Phase 2 Scoping Memo's Issues 2 through 4 are attached to this Final Report. Parties will have a further opportunity to clarify and/or advance their positions on matters within the scope of WG 3 in opening and reply comments on this Final Report.

A. Co-Chair Consensus Proposals for Adoption by the Commission

The Co-Chairs respectfully submit for approval by the Commission the following "Consensus Proposals." These proposals are discussed in further detail in subsequent sections of this report.

1. Adopt the following allocation and market offer-based frameworks for disposition of the IOUs' PCIA-eligible products. The approach considers four products – Local Resource Adequacy ("RA"), System and Flexible RA (or "System and Flex RA"), greenhouse gas ("GHG")-free energy, and Renewables Portfolio Standard ("RPS") energy.[2] The table below provides a high-level summary of the proposals:

Product	Framework	Description
Local RA	Allocation	• Allocation of the IOUs' PCIA-eligible Local RA portfolio to all PCIA-eligible load serving entities ("LSE")[3] based on their forecasted, vintaged, coincident peak load share (MW) • Allocations will utilize a "CAM-like" mechanism (the "PCIA Showing") in which the IOU shows capacity on behalf of other LSEs

[2] While System and Flexible RA are two distinct products/attributes, they may be collectively referred to as one product within the context of this Final Report.

[3] Throughout this Final Report, reference to PCIA-eligible LSEs is intended to include the IOUs.

System and Flex RA	Voluntary allocation and market offer	• PCIA-eligible LSEs will be provided an annual option to receive an allocation from the IOUs' PCIA-eligible System and Flex RA portfolios based upon each LSE's forecasted, vintaged, coincident peak load share (MW) • Declined allocations will be offered by the IOUs to the market twice annually through a competitive solicitation process (the "Market Offer") • System and Flex RA will utilize the PCIA Showing mechanism for allocations
GHG-Free Energy	Voluntary allocation	• PCIA-eligible LSEs will be provided an annual option to receive an allocation of GHG-free energy from the IOUs' PCIA-eligible large hydroelectric and/or nuclear portfolios based upon each LSE's forecasted, vintaged, annual load share (MWh) • Declined allocations will be reallocated among the PCIA-eligible LSEs that accepted allocations in accordance with their forecasted, vintaged, annual load shares
Renewables Portfolio Standard Energy	Voluntary allocation and market offer	• PCIA-eligible LSEs will be provided an annual option to receive an allocation from the IOUs' PCIA-eligible RPS energy portfolios based upon each LSE's forecasted, vintaged, annual load share (MWh)

		• To receive long-term contracting benefits from allocations, however, an LSE must elect to take its allocations through the remaining life of the longest contract in their PCIA vintage, which must last at least 10 years from the allocation start date[4] • Declined allocations will be offered for sale by the IOUs through a Market Offer process. IOUs will make a portion of declined allocations available through long-term sales contracts, as described in more detail in this report

The WG 3 discussion on these approaches was robust and shared broadly at the workshops, and with the Co-Chairs' respective stakeholders. Feedback and input from commenting parties helped shape this final proposal. All customers (bundled and unbundled) equitably benefit by receiving the products or the value of those products already purchased on their behalf by the IOUs, and LSEs have the flexibility and autonomy to manage the composition of their own portfolios by choosing whether to accept or decline a portion of their allocations. The details of this Consensus Proposal on Issue 1 of the Phase 2 Scoping Memo are discussed in Section V herein.

2. Adopt updates to the PCIA ratemaking mechanism to be implemented in conjunction with above described mechanisms, as described in Section V.H herein:
   a. Apply a $0/kW-month ("kW-mo") Market Price Benchmark ("MPB") to the Local RA attributes. A one-time exclusion from the PCIA rate cap shall be permitted to accommodate the additional costs associated with the implementation of the Local RA allocation.
   b. Treat System and Flex RA and RPS energy allocations like sales to the LSE receiving the allocation, priced at the applicable year's attribute MPB value

[4] A grandfathering provision will apply in the first election opportunity to grant vintages that lack contracts with at least ten years remaining a one-time opportunity for long-term treatment if certain criteria are met. See Section V.D.2.b.

according to the forecast and true-up mechanisms contemplated by D.19-10-001, with revenues offsetting costs in the Portfolio Allocation Balancing Account ("PABA") according to the existing PCIA framework's treatment of sales.

c. Allocate all sales revenues from the Market Offer process across the PABA vintaged sub-accounts in proportion to the allocation volumes declined in each vintage.

d. Re-allocate any unsold System and Flex RA and RPS energy on a forecasted, vintaged, peak- and annual-load share basis, respectively, to all LSEs at $0. Such re-allocated attribute volumes shall be treated as sales at $0 and incorporated into the relevant MPB by the CPUC's Energy Division ("ED") as any other reported sales transaction would be, as contemplated by D.19-10-001.

e. During the transition period prior to full implementation of the RPS energy Voluntary Allocation and Market Offer ("VAMO") proposal, only RPS generation, excluding banked RECs, that (i) is offered for sale by the IOU, (ii) remains unsold, and (iii) is in excess of the IOU's interpolated annual RPS compliance target is to be valued at $0/MWh.

3. Direct the IOUs to issue a Request for Interest ("RFI") in 2021 and 2022 to solicit interest from their RPS counterparties in pursuing agreements to optimize the PCIA portfolios. The RFI will solicit interest from IOU counterparties to potentially contract with other LSEs for buy-outs or full assignments of the IOU's RPS contracts that would remove the contracts from the IOU's portfolio. The IOUs will connect interested counterparties with LSEs, who will be free to engage in negotiations. Any final agreement between the counterparty and other LSE will be subject to agreement by and among the counterparty and IOU, and approval of the Commission for IOU cost recovery purposes.

   The RFI will, coincident with the request for potential contract assignments, solicit offers from contract counterparties for proposed terminations, buy-outs, or amendments that may result in net cost savings or added value for customers. The IOUs will evaluate counterparties' proposals and will seek to negotiate agreements to amend or terminate the counterparty's contract, if doing so is deemed by the IOU to be in the best interest of all customers. The IOUs will include any successful agreements in their annual Energy Resource Recovery Account ("ERRA") Review of Operations application filings or through an advice letter or other application, as appropriate, for Commission review and approval. The details of this Consensus Proposal on the Phase 2 Scoping Memo's Issue 2 are discussed in Section VI herein.

4. Direct each IOU to report on its implementation and outcomes of the new RFI processes in an appropriate venue (to be determined) as proposed in Section VI.B.2.e., including identifying all rejected offers and the basis for not moving forward in negotiations or any ultimately unsuccessful outcome. Additionally, the IOUs will report or continue to report in their annual ERRA Review of Operations applications, as applicable: (1) material events of defaults, any termination rights associated with such material events of default, and any actions taken with respect thereto; and (2) cost savings received from active portfolio management.
5. Address issues associated with the implementation of the above proposals within relevant Commission proceedings (*e.g.,* Integrated Resource Planning ("IRP") Order Instituting Rulemaking ("OIR") (R.16-02-007), RPS Procurement Plans (R.18-07-003), Bundled Procurement Plans ("BPP"), and RA OIR (R.17-09-020), as required). BPP and RPS Procurement Plan updates will conform to the WG 3 Final Decision establishing the allocation, Market Offer, and RFI processes. The Co-Chairs propose that the Commission issue a decision in Track 4 of the RA OIR by June 2021 ruling upon the modifications needed to the RA process and timelines, establishment of the PCIA Showing mechanism, and establishment of methodologies for LSEs to submit and the CPUC and/or California Energy Commission ("CEC") to calibrate vintaged annual- (MWh) and peak- (MW) load forecasts. In addition, the Commission may

need to engage the California Independent System Operator ("CAISO") and CEC to update processes, procedures, rules, and requirements to the extent necessary. Finally, each IOU shall be given sufficient time to update its BPP and RPS Procurement Plan to incorporate the Consensus Proposals, as required, and sufficient time should be provided for the Commission to approve modifications for implementation of the Co-Chairs' proposals.

6. Subject to timely completion of the implementation of the WG 3 proposals in the regulatory venues contemplated in Item 5, above, the Co-Chairs propose that full implementation of the allocation proposals take place in 2022 for 2023 deliveries of RPS energy, GHG-free energy, and System and Flex RA, and 2022 for the 2024-25 compliance years for Local RA.
7. The Co-Chairs propose that an interim approach to voluntary GHG-free energy allocations be implemented at the earliest possible date following the WG 3 Final Decision for deliveries starting in 2021.
8. The Co-Chairs recognize the broad authority of the Commission over IOU activities, and, other than as provided in Consensus Proposal 4, above, do not recommend that any new or modified standards for IOU shareholder responsibility for portfolio mismanagement are required at this time.

The Co-Chairs submit that their Consensus Proposals represent reasonable, thoughtful and workable compromises across a broad spectrum of the stakeholder interests in WG 3 and should be adopted by the Commission. The Consensus Proposals resolve all issues in WG 3 except for the Non-Consensus Items, discussed below.

B. <u>Non-Consensus Items Requiring Resolution by the Commission in its Final WG 3 Decisions</u>

Despite best intentions and thorough discussions, the Co-Chairs were unable to reach consensus on the following issues (the "Non-Consensus Items"), which are described in more details in the referenced sections of this Final Report. The Co-Chairs anticipate that each may file separate comments in support of their positions below.

1. Should there be a Market Offer process for Local RA?[5]
    a. SCE and CalCCA propose that all parties will be provided an allocation which may not be declined, and there will be no Market Offer of Local RA.
    b. Commercial proposes that Local RA be subject to a voluntary allocation followed by a Market Offer, similar to the System and Flex RA proposal.
2. What are the appropriate steps and timelines for interim allocation and Market Offer processes to take effect?[6]
    a. SCE proposes that interim RPS energy voluntary allocations be implemented in 2021 for 2022 deliveries on the basis of the LSEs' actual, vintaged, annual load shares, but without a Market Offer process. To the extent that implementation of such RPS energy allocations would jeopardize the IOUs' abilities to meet their RPS compliance requirements, cause undue cost increases, or cause cost shifts to bundled service customers, the IOUs may petition the Commission to delay interim implementation. SCE opposes an interim implementation of RA allocations prior to full implementation in 2022 for 2023 for System and Flex RA and for 2024-25 for Local RA.
    b. CalCCA and Commercial support an interim implementation of the RPS energy voluntary allocation at the earliest possible date following the WG 3 Final Decision, for deliveries beginning in 2021. An interim implementation of the RA frameworks is proposed to commence in 2021, pending the WG 3 Final Decision, for System and Flex RA voluntary allocations for the 2022 compliance year and Local RA allocations for the 2023 and 2024 compliance years.

---

[5] See Sections V.B.2.b and V.B.4.

[6] See Section VII.B.

3. Should payments made by the IOU pursuant to certain Commission-approved contract buy-outs, assignments, terminations or other optimization activities be excluded from the PCIA rate cap adopted in D.18-10-019?[7]
    a. SCE and Commercial support a process that allows the IOUs to submit an advice letter to request exclusion of specific portfolio optimization payments that may require up-front payments but result in savings to customers in subsequent years.
    b. CalCCA opposes a carve-out from the PCIA rate cap of any additional costs associated with Commission-approved RPS contract buy-outs, assignments, terminations or other optimization agreements.
4. To what extent can the IOUs be subject to disallowance risk based on actions not taken in response to the RFI, as submitted in a report on the RFI process? How often should the report be filed, when, and in what venue? [8]

    The Co-Chairs were unable to reach consensus on the timing, frequency, and venue for the RFI report, and extent to which the IOUs are subject to disallowances by the Commission based on actions not taken within the RFI process.

Positions on the Non-Consensus Items are set forth in more detail in the referenced sections of this Final Report. Each Co-Chair, along with other parties to this proceeding, will have the opportunity to submit individual opening and reply comments advancing its positions on these Non-Consensus Items. The Co-Chairs request that the Commission resolve each of these Non-Consensus Items in its final decision addressing the WG 3 issues.

III.

BACKGROUND

On October 11, 2018, the Commission issued D.18-10-019 modifying the PCIA methodology and opening a second phase of this proceeding to enable parties to further develop

[7] See Section VI.B.2.d.

[8] See Section VIII.C.

proposals for portfolio optimization and cost reduction for future consideration by the Commission.[9] On February 1, 2019, the Commission issued the Phase 2 Scoping Memo, directing parties to convene three working groups to further develop PCIA-related proposals for consideration by the Commission.

Due to the complexity and number of issues to be resolved in WG 3, the Phase 2 Scoping Memo anticipated a final report on consensus and non-consensus issues by January 30, 2020, with a proposed decision to be issued by second quarter 2020. The schedule was permitted to be further modified by assigned Commissioner or Administrative Law Judge ("ALJ") as required to promote the efficient and fair resolution of the issues scoped in the proceeding. The Co-Chairs requested an extension to file the Final Report to February 21, 2020 due to the breadth of the WG 3 scope.[10] This request was approved by the ALJ on January 22, 2020 and moves the expected date for a Proposed Decision to third quarter ("Q3") 2020.[11] This report satisfies the requirement of a final report on WG 3's activities, as described in the Phase 2 Scoping Memo.

A. WG 3 Co-Chair Responsibilities

As directed in the Phase 2 Scoping Memo, the Co-Chairs of WG 3 are responsible for the following tasks:

1. Scheduling the Working Group's meetings, and associated logistics;
2. Addressing each of the Commission-directed topics and schedule;
3. Holding Workshops; and
4. Preparing and filing periodic reports according to the schedule for WG 3.

B. Procurement Guide

The Phase 2 Scoping Memo recognized that the Working Groups would be more efficient if all participants were provided with a common reference guide on how the IOUs' portfolios have developed over time and in compliance with statutory and Commission requirements.

---

[9] D.18-10-019, p. 97.

[10] Email Request of WG 3 Co-Chairs for Additional Changes to Remaining Schedule, Jan. 17, 2020.

[11] Administrative Law Judge's Ruling Modifying Proceeding Schedule, Jan. 22, 2020 at 2.

Pursuant to the Phase 2 Scoping Memo, the IOUs hosted a meet-and-confer session via conference call to develop an outline for the Procurement Process Reference Guide ("Guide"). All parties were invited to participate. The IOUs incorporated participants' input into a final outline, which was served on March 11, 2019. The IOUs used the final outline to produce the Guide, a draft of which was provided to CPUC staff for review on April 4, 2019. The final Guide was sent to the service list on April 25, 2019.

IV.

PROCESS FOR WG 3

A. Principles for WG 3 Work

The Co-Chairs agreed that the following principles should govern the work of WG 3:

- Work collaboratively in good faith toward practical and commercially viable solutions for the benefit of all customers.
- Be consistent with California statutes, CPUC decisions, energy policy goals and mandates.[12]
- Respect the terms of existing Power Purchase Agreements ("PPAs") between power suppliers and IOUs.[13]
- Allow alternative providers to be responsible for power procurement activities on behalf of their customers, except as expressly required by law.[14]

B. Regular Meetings of WG 3 Co-Chairs

Beginning on March 27, 2019, the WG 3 Co-Chairs met once a week, usually by conference call but also in person, as needed. Over the past 3 to 4 months, the Co-Chairs have met two times per week, as needed to review details and reach agreement. The weekly call among the Co-Chairs was held on Wednesday afternoons for approximately 2.5 hours, with the second weekly meetings taking place on Friday afternoons for approximately 2 hours. The

---

12 Phase 1 Scoping Memo, 1.e.

13 Phase 1 Scoping Memo, 1.k.

14 Phase 1 Scoping Memo, 1.f.

purpose of these calls was to gain consensus, share concepts and proposals, identify areas of alignment and non-alignment, and define subsequent action items. To facilitate active participation, presentations and written proposals were developed and circulated in advance of these calls to allow the Co-Chairs to review the material internally and with their constituents prior to the weekly meetings. The Co-Chairs met in person, generally prior to the workshops, to focus attention on finalizing consensus and non-consensus proposals and compiling the workshop presentations. The meetings have been active, collaborative in nature, and well-attended by the representatives and constituents of the Co-Chairs.

C. Working Group 3 Workshops

As required by the Phase 2 Scoping Memo, the Co-Chairs held four workshops to which all stakeholders and intervenors to the proceeding were invited. A notice was sent to the service list indicating the location, date, and time of each workshop. In advance of each of these workshops, the Co-Chairs disseminated presentation materials. Additionally, options were provided for both in-person and WebEx or Skype attendance, to ensure inclusion of all parties. Parties were encouraged to ask questions or make comments throughout the presentations. There was robust engagement by the audience and those participating by WebEx or Skype, at each of the workshops. A more detailed description of the content covered in each workshop is attached in Appendix F.

Following each workshop, parties were invited to provide informal comments. The feedback received was helpful in that it provided the Co-Chairs with a better perspective on the various stakeholders' positions, concerns, and alternative proposals. The presentations and informal comments received from the participants in the first two workshops were attached to the Co-Chairs' First and Second Progress Reports. The presentations and parties' informal comments on the Third and Fourth Workshops, and on proposals for Issues 2 to 4, are attached hereto in Appendices A to E.

D. Working Group 3 External Stakeholder Engagement

In addition to the public engagement with stakeholders participating in the formal workshops, the Co-Chairs established a SharePoint site, managed by SCE, to provide a single repository of the workshop materials, informal comments, and the Co-Chairs' meeting agendas and work plan for the WG 3 project. The Co-Chairs also submitted their own reply comments to the service list in response to informal comments from the Second Workshop. Additionally, the Co-Chairs engaged in a number of conversations with third parties outside of the immediate participants in the Working Group process. More information on the WG 3 external engagement is provided in Appendix F.

V.

SCOPING ISSUE 1: STRUCTURES, PROCESSES, AND RULES GOVERNING PORTFOLIO OPTIMIZATION

A. Introduction to Proposal

1. Background

The Co-Chairs explored several frameworks for optimizing the IOUs' existing portfolios and attributing portfolio resources to those customers paying for them. Two main conceptual approaches were considered: (i) an excess sales approach in which the IOUs offer attributes in excess of bundled service customers' compliance requirements to the market; and (ii) an allocation-based approach that allocates attributes from the IOUs' respective PCIA-eligible portfolios to all LSEs serving customers paying the PCIA. Within the second alternative, the Co-Chairs examined several allocation and sales mechanisms, including mandatory allocations, voluntary allocations, and a combination of allocations and sales or "market offers."

2. Excess Sales Concept

The Co-Chairs began by exploring an "Excess Sales" concept wherein the IOU would retain the portion of its procured resource attributes needed to serve its bundled service compliance requirements and would offer attributes in excess of such needs for sale to the market.

With respect to RA specifically, the Co-Chairs were challenged in finding alignment in three primary areas centering on the definition of "excess," as follows:

- Methodology for determining the amount of RA capacity retained by the IOU in excess of its compliance requirement ("Buffer"). IOUs have historically reserved some additional capacity to account for foreseeable regulatory requirements (*e.g.,* to meet outage substitution requirements) and unforeseen deficiencies (*e.g.,* Net Qualifying Capacity ("NQC") reductions, contract defaults, operational constraints (such as those based on hydrological conditions), etc.);
- Timing for making excess RA available to the market relative to establishment of final RA requirements, the year-ahead showing, and the month-ahead showings;
- Treatment of capacity not shown in supply plans to account for known operational constraints, reduced water levels, outages, maintenance, permitting, or other constraints.

Although these areas of non-consensus arose in the context of RA specifically, the challenges encountered in establishing the "excess" amount were expected to also arise in addressing sales of excess RPS energy.

3. Allocation Concepts

The discussions on allocations focused on developing frameworks by which LSEs of customers who had departed bundled service could receive their customers' share of the PCIA-eligible attributes procured on their behalf when they were bundled service customers. Each PCIA-eligible LSE's allocations are based upon a proportional share of the IOU's entire PCIA-eligible, vintaged position. The allocation methodologies were viewed positively by the Co-Chairs because they avoid concerns about how to define excess attributes and therefore prevent disputes regarding the volume of attributes an IOU is required to make available to the market. Additionally, allocations ensure that all attributes are appropriately distributed among all LSEs, so their customers are able to realize the value they are paying for.

Initially, allocation discussions focused on Local RA and GHG-free energy. CalCCA proposed an allocation of all Local RA to LSEs in proportion to their peak load contribution to ensure capacity in tight local areas is distributed fairly among the LSEs. The Co-Chairs also discussed a concept for a voluntary allocation of GHG-free energy where LSEs would receive their share of attributes and be allowed to reflect the energy on their Power Content Labels ("PCL"), subject to the CEC's rules. The Co-Chairs agreed that this approach was an equitable method of distributing attributes for those Local RA and GHG-free resources procured on all customers' behalf. After initial success with Local RA and GHG-free energy, the Co-Chairs considered additional allocation-based approaches for System and Flex RA and RPS energy.

4. Voluntary Allocation and Market Offer Concept

In Phase 1 of R.17-06-026, Commercial developed its Voluntary Allocation and Auction Clearinghouse ("VAAC") proposal under which the IOUs would annually offer a voluntary allocation of their excess PCIA-eligible resources and then auction off any unallocated attributes. The VAAC proposal formed the basis for the Co-Chairs' Voluntary Allocation and Market Offer ("VAMO") proposal for RPS energy and System and Flex RA attributes within the IOUs' PCIA-eligible portfolios. Under the VAMO framework, PCIA-eligible LSEs would be provided a voluntary allocation of PCIA-eligible products, with any unallocated products being sold through an annual "Market Offer" process.

The Co-Chairs have reached alignment on most major issues regarding the methods for treating each product. The Co-Chairs' proposals regarding each of the four products are outlined below.

B. Resource Adequacy

1. Background on Resource Adequacy

System RA is designed to ensure that there is enough generating capacity on a year-ahead basis to meet monthly peak load requirements, while Local RA is designed to address capacity requirements on a multi-year basis within specific CAISO transmission constrained areas. System RA requirements are determined based on each LSE's CEC-adjusted, coincident peak load forecast for each month plus a 15 percent planning reserve margin. RA procured from local resources can simultaneously be used to meet both Local, System, and Flexible RA obligations. Flexible RA is designed to ensure that sufficient dispatchable energy exists within the CAISO system to meet the ramping needs resulting from increased renewable penetration in California. Flexible RA requirements are based on an annual CAISO study that currently looks at the largest three-hour ramp for each month needed to run the system reliably.[15]

The CAISO evaluates each resource's NQC to identify its ability to contribute to meeting peak capacity needs. For System RA and the CAISO's evaluation of Transmission Access Charge ("TAC")-area Local RA requirements, the resource's NQC in each month is used to determine its contribution to that month's RA requirements. However, in the CPUC's evaluation of a resource's contribution to meeting an LSE's Local RA showing requirement, only the August NQC value is used for each showing month of the year.[16] A resource's contribution to meeting Flexible RA is determined by the resource's Effective Flexible Capacity ("EFC") for each month in the year, as determined by the CAISO. The CAISO typically publishes the final NQC and EFC for resources in late September.

As part of the RA process, LSEs submit their historical loads in March and forecasted loads for the next compliance year in April to the CPUC and CEC for calibration and identification of the coincident peak load shares.[17] Based upon these calibrated forecasts, the ED publishes LSEs' initial RA requirements, including their preliminary allocation share of Cost Allocation Mechanism ("CAM") and demand response ("DR") capacity, in July, and the final RA requirements and CAM share in late September.[18] LSEs' year-ahead compliance filings are

[15] CPUC 2020 RA Guide at 19.

[16] *Id.*

[17] CPUC 2020 RA Guide at 7.

[18] *Id.*

due to the CAISO and the CPUC on October 31 of each year for the forthcoming compliance year(s).[19]

Within the year-ahead RA filing, LSEs must meet 90 percent of their year-ahead requirement for System RA (for May to September) and Flexible RA (for all 12 months) and 100 percent of their multi-year Local RA requirement for the first and second compliance years and 50 percent of their multi-year Local RA requirement for the third compliance year.[20] LSEs are required to meet 100 percent of their Local, System, and Flexible RA requirements in the monthly compliance filing, which is due 45 calendar days prior to the showing month.

The current RA process includes a monthly and quarterly load forecast filing by LSEs. The monthly load forecast filing provides the needed information to the Commission to adjust an LSE's System RA requirements to account for intra-year load migration, while the quarterly load forecast filing provides the needed information to adjust an LSE's CAM and Reliability Must Run allocations.

Discussions are currently progressing in the RA OIR about the need and potential role for a Central Procurement Entity ("CPE") for Local RA procurement. Additionally, the CAISO's RA Enhancements Initiative is contemplating, among other things, how to appropriately value the capacity contribution pursuant to an Unforced Capacity availability ("UCAP") methodology, including for use-limited resources.[21] The Co-Chairs' proposal does not consider the potential impact of the establishment of such a CPE or UCAP methodology. However, to the extent that these changes or any other regulatory changes occur, the proposed allocation methodologies should be adapted to incorporate the impact of these regulatory requirements and processes.

2. <u>Co-Chair Consensus Proposals</u>

---

[19] *Id.*

[20] *Id.* at 4.

[21] Use-limited resources are resources that are subject to de-rates due to limitations upon their ability to operate to their maximum capacity output (NQC), maximum run times, or frequency of use, etc. as a result of issues such as insufficient fuel, air permit restrictions, charging restrictions, or other constraints.

a) Overview of RA Allocations

The Co-Chairs propose that the determination of LSEs' RA allocations will be calculated on the basis of each LSE's forecasted, vintaged, coincident peak-load share as informed by the year-ahead RA procurement obligations within the RA process, in a similar manner to CAM. The PCIA-eligible, vintaged RA positions to be allocated will be set in the IOUs' July CAM filings to the Commission, as updated for NQC and EFC adjustments by CAISO. Prior to this deadline, the IOUs may sell, swap, trade, or otherwise dispose of their Local, System, and/or Flexible RA attributes for portfolio optimization purposes, and only the residual volumes would be subject to allocation. Any change in Local, System, and/or Flexible RA positions due to non-resource specific portfolio optimization will be shared proportionally from each vintage. Any portfolio optimization activity pertaining to a specific resource, such as an amendment, termination, or assignment, will affect the costs and attribute positions within the resource's vintage only. The allocations will be conveyed through a mechanism structured similarly to CAM, however, they will be on a vintaged basis, known herein as the "PCIA Showing."

b) Overview of Local RA Allocation

The Co-Chairs propose that the IOUs' PCIA-eligible Local RA positions be subject to an annual allocation among all PCIA-eligible LSEs for the multi-year Local RA compliance showing. As with Local RA obligations, allocated Local RA volumes for years 2 and 3 will be based upon the forecasted, vintaged, annual[22] peak-load (MW) share for the first year for which showings are required (the "prompt year") only (rather than the forecasted peak-load shares in years 2 and 3), and will thus only be indicative and will be updated in the following year on the basis of updated load shares and RA positions. Only Local RA capacity from within the IOU's TAC area will be subject to this Local RA allocation. All non-TAC area, PCIA-eligible Local RA capacity held by the IOU for system and/or flex RA purposes will be treated as System and Flex RA for PCIA allocation purposes. The IOUs may continue to perform portfolio

[22] Historically this has been the August peak, but more recently September peak.

optimization activities to maximize the value of the non-TAC area Local RA attribute. Any System and Flex RA attributes associated with an IOU's local resources within that IOU's TAC area will also be allocated as Local RA. SCE and CalCCA propose that LSEs may not decline their Local RA allocation and there will be no Market Offer process for Local RA. Commercial supports a voluntary allocation of Local RA followed by a Market Offer of any unallocated Local RA.

c) Overview of System and Flex RA VAMO

The Co-Chairs propose that System and Flex RA be made available annually to PCIA-eligible LSEs through a voluntary allocation that will offer two election opportunities, in the spring and in the fall, in the year prior to the compliance year. In the spring election, PCIA-eligible LSEs may elect to decline up to 50 percent (in 10 percent increments) of their eligible allocation share, which would then be offered for sale in the spring Market Offer process. In the fall, PCIA-eligible LSEs will make a final election to take a constant percentage (in 10 percent increments) of their forecasted, vintaged, monthly, peak-load share as an allocation for the compliance year, which will be multiplied by each month's PCIA-eligible, vintaged RA position, to determine that LSE's allocation quantities for each month. The System and Flex RA allocations that are declined by LSEs will be made available for sale by the IOU through a Market Offer process occurring twice annually, in the spring and fall in the year prior to the compliance year. In alignment with current protocols for all solicitations, an Independent Evaluator ("IE") will participate in the Market Offer process.

d) PCIA Showing

The Co-Chairs propose a "PCIA Showing" for the distribution of the IOUs' PCIA-eligible RA capacity, which will function in a similar fashion as CAM, except on a vintaged basis. In this proposed PCIA Showing, the IOU is transferred a portion of the peak-load from other LSEs and must show the RA capacity from the PCIA-eligible resource or a substitute resource to serve that portion of the PCIA-eligible LSE's load. Each PCIA-eligible LSE's RA obligation will be reduced based upon their allocation or Market Offer purchase, and the IOU will show the PCIA-eligible resources' RA capacity, or substitute capacity, on behalf of itself and the corresponding LSEs in the IOU's RA compliance showing. As described in Section V.F, the Co-Chairs propose that ED determine the forecasted, vintaged, monthly, coincident peak-load shares and capacity allocated to each LSE within the PCIA Showing. A process will need to be developed within the RA OIR to calibrate LSEs' vintaged, coincident peak-load shares, similar to that process currently performed by the CEC for determining coincident peak demand. Each LSE would then report its PCIA-eligible RA capacity credit, or in the case of the IOUs, the PCIA-eligible RA capacity debit, on its year-ahead and month-ahead RA filings with the CPUC and CAISO. The allocated and sold RA positions, resulting from the VAMO proposal, will be finalized in the PCIA Showing for the compliance year by the October 31 year-ahead RA compliance filing.

e) System RA and Flex RA Market Offer Process

The Co-Chairs propose that the IOUs offer to the market any declined allocation of System and Flex RA through a competitive solicitation ("Market Offer") process. Because RA compliance is subject to predefined requirements and compliance filing deadlines, the Co-Chairs propose that the System and Flex RA Market Offer will be conducted twice annually, in the spring[23] and the fall[24], for deliveries in the prompt year.

The Co-Chairs propose that System and Flex RA Market Offer contracts will have terms ranging from one calendar month to one calendar year in length. The sales will be structured as shares of the PCIA Showing, rather than as typical RA tags. This may require that the IOUs develop new sales contracts, but each IOU may determine the appropriate form for its purposes. Offers will be valued on the basis of revenue maximization until all volumes are sold. Revenues will flow through the PABA as a credit against the PCIA costs, and will be allocated to the vintaged PABA sub-accounts on the basis of the vintages from which the RA volumes available

[23] See Section V.B.2.e.1.

[24] See Section V.B.2.e.2.

for sale were sourced.[25] Buyers may be required to provide appropriate credit, collateral, netting agreement terms, or other commercial arrangements to protect all customers from defaults, which could otherwise lead to higher PCIA rates.

The Market Offer process for System and Flex RA will be conducted using Commission pre-approved mechanisms for solicitation administration, valuation, selection, and contracting, which will be proposed by the IOUs within their BPPs or an advice letter requesting Commission approval to launch the Market Offer. Additionally, the Market Offer processes will be monitored by an IE, and the CAM review group will be consulted on offer selections. The Market Offer process will be open to all market participants, including the IOU holding the Market Offer process, but to participate the hosting IOU may be required to (i) submit bids to the IE and ED in advance of the Market Offer's launch or (ii) establish dual procurement teams separated by an ethical wall, with monitoring by the IE.

(1) <u>Spring System and Flex RA Voluntary Allocation and Market Offer Process</u>

The Co-Chairs propose that PCIA-eligible LSEs will have an opportunity in April prior to the compliance year to decline a portion of their anticipated annual allocation. By mid-April, the PCIA-eligible LSEs will have calculated their year-ahead load forecasts for the RA process, and the IOUs will have filed their indicative PCIA-eligible, vintaged RA positions. This information gives PCIA-eligible LSEs an estimate of their eligible allocation amounts for planning purposes.

In the spring election, each LSE may choose to either defer their decision to the fall election period or may make a binding decision to decline up to 50 percent of their allocation (in 10 percent increments). The declined volumes to be made available for sale in the spring Market Offer process will be calculated according to the previous year's forecasted, coincident, peak-

---

[25] For an example of how the valuation is proposed to work and revenues are to be allocated, refer to Appendix H on Table 46 and Table 52, respectively.

load shares and the current vintaged, PCIA-eligible RA position. Any unsold quantities in the spring Market Offer will be offered for sale in the fall Market Offer.

Parties bidding into the spring Market Offer will bid for firm quantities of System and Flex RA within the PCIA Showing. However, LSEs' final allocation shares will not be known until late September, pending the final publication of the (i) LSEs' forecasted, vintaged, monthly, coincident peak-load shares, (ii) IOUs' PCIA-eligible RA positions, and (iii) resources' final NQC or EFC values. Therefore, LSEs who elect to decline a portion of their allocations in the April election opportunity bear the risk that final allocation volumes may result in less capacity being available to them in the fall VAMO process.

(2) Fall System and Flex Market Offer Process

Under the existing RA process, the fall allocation elections will be submitted following the CPUC's publication of the final RA procurement requirements and the final PCIA allocation shares in late-September, and the final RA year-ahead showing is due on October 31. This leaves a tight window to conduct the IOUs' fall Market Offer process in which all declined allocation volumes, including any unsold attributes from the spring Market Offer, will be offered for sale. This timing issue is exacerbated as LSEs, including the IOUs, may need to continue performing incremental RA procurement following the completion of the IOUs' fall Market Offer processes to meet their year-ahead compliance requirements. The fall Market Offer process should be completed as soon as practical to provide enough time for the Commission to finalize the PCIA Showing credits and debits, allow LSEs to conduct any incremental procurement, and allow LSEs to prepare their year-ahead RA showings. This is an aggressive and tight timeline for conducting all of the requirements implied by the Market Offer and subsequent incremental procurement. Additionally, there must be sufficient time provided following the Market Offer processes to incorporate the sales prices and volumes into the Update to ERRA Forecast applications, due in early November of each year. Thus, the Co-Chairs propose that the Commission order that Track 4 of the RA OIR revise the existing RA process timelines to move them forward in the year, to take into account the additional steps required of

LSEs and the regulatory agencies, including the CPUC, CEC, and CAISO, by the System and Flex RA VAMO process with a final decision by June 2021.

(3) Unsold System and Flex RA

The Co-Chairs propose that any unallocated System and Flex RA that remains unsold in the fall Market Offer should be subsequently allocated at no cost and pro-rata among all LSEs on the basis of LSEs' forecasted, vintaged, peak-load shares. These re-allocations will be reported by the IOUs to ED and should be included in the System or Flex RA MPBs as if they are RA sales transactions at $0/kW-mo, reflecting the specific quantities unsold. An example of how the re-allocation is performed is included in Appendix H in Tables 49 and 50.

f) Intra-Year Load Migration

While the CAM mechanism has processes for addressing intra-year load migration, and thus allows for re-allocation of CAM capacity on a quarterly basis, the Co-Chairs propose not to permit intra-year load migration adjustments to the allocated PCIA-eligible RA volumes. However, if a new LSE has filed with the Commission to form midway through the compliance year and has a year-ahead RA showing obligation, that LSE would be eligible for its RA allocations from the start of its RA obligation period. The Co-Chairs propose that a report be published by ED to evaluate whether such a re-allocation for load migration should be incorporated into the mechanism after it has been in effect for two years.

g) Substitution for Unavailable RA

Under the current CAISO Tariff, the IOUs, as the scheduling coordinator for the PCIA-eligible resources, as applicable, are responsible for providing substitution capacity for shown capacity that is on a planned or forced outage.[26] If substitution capacity is not provided, the CAISO may exercise its authority and disapprove the planned outage or cancel the previously approved planned outage or assess Resource Adequacy Availability Incentive Mechanism

[26] CAISO Tariff, Sept. 28, 2019, at 203.

(“RAAIM”) penalties.[27] Under the Co-Chairs’ proposal, the IOUs are constrained from reserving capacity from the PCIA-eligible portfolio to mitigate foreseen and unforeseen portfolio risks associated with the PCIA-eligible resources, such as planned outages (but not use-limited resources, which may be de-rated). Accordingly, the Co-Chairs recognize that the PCIA-eligible RA costs may increase as the IOU may need to procure additional capacity for substitution in the Delivery Year[28] to manage the PCIA portfolio on behalf of all customers. As with CAM, the Co-Chairs propose that the IOUs recover the costs associated with procuring or attempting to procure substitution capacity through rates. In this case, the Co-Chairs propose to allocate the costs of substitution capacity or other RA capacity required to manage the PCIA-eligible portfolio in compliance with CPUC and CAISO regulations through the PABA according to the vintaged sub-account to which the resource requiring substitution capacity belongs. The Co-Chairs propose the same general cost recovery rules as in the CAM[29], with minor adjustments:

1. To the extent the IOU has excess RA in its bundled position, the IOU may transfer such excess RA to the PCIA Showing and charge the PABA vintage subaccount for the relevant resource at the relevant MPB.[30]
2. If the IOU procures substitution capacity in the market, the actual capacity price paid shall be charged to the resource’s PABA vintage sub-account for cost recovery.
3. If the IOU is unable to procure substitution capacity and incurs CAISO capacity procurement mechanism (“CPM”) charges, RAAIM penalties, any costs

---

27 *Id.* at 205.

28 “Delivery Year” means the immediate year to which the allocation elections pertain, or as the context requires, the current year in which deliveries of attributes shall be made to realize the allocation elections

29 CPUC 2020 RA Guide at 24.

30 For Local RA, it is assumed that ED will continue to publish the Local RA MPBs based upon market transactions, despite $0/kW-mo value being ascribed to Local RA in the PCIA. If this is not the case, then an alternative method should be developed to appropriately compensate IOUs for substitution of Local RA resources.

associated with cancelling and/or moving the outage, and/or other related costs, charges, or penalties, then such costs, charges, or penalties shall be charged to the relevant PABA vintage sub-account for appropriate cost recovery.

h) Trading of Allocated RA

The Co-Chairs propose that LSEs may enter into sales, trades, swaps, or other transaction types for the transfer or sale of their allocated share of RA in the PCIA Showing. An LSE may transact its shares any time following the allocation, and the IOU would have no further involvement in the transaction nor an obligation to report the transaction. LSEs selling their RA allocation would report a debit, and LSEs buying an RA share of the PCIA Showing would report a credit, to ED on the LSE Allocations tab of the RA template submitted at the year-ahead and month-ahead RA showings.[31]

3. Rationale for Co-Chairs' Consensus Proposals

a) Allocation of Local RA is Reasonable

The Local RA allocation proposal achieves the goal of optimizing the IOU's PCIA-eligible portfolio through the proportional allocation of products and value to all customers – bundled and departed load – that bear cost responsibility. Full allocation of PCIA-eligible Local RA is superior to an "Excess Sales" approach because it eliminates the need to address the complex issues of the size of the Buffers and uncertainty tranches and the timing of sales.

Various LSEs expressed concerns throughout the WG 3 process about the IOUs not making sufficient Local RA capacity available to the market. The proposed allocation of Local RA avoids the complexities arising from the existing constraints and potential market power issues that might exist in certain Local RA-constrained geographical areas, particularly in disaggregated local areas. Additionally, the recent expansion of the Local RA requirement to a multi-year forward requirement complicates matters when exploring the potential application of

[31] If the IOU procures a share of the PCIA Showing in the Market Offer process or through secondary trading, the IOU will receive a credit towards its compliance requirements, which will net against the debit it otherwise would realize against its RA compliance obligations for showing the PCIA-eligible RA on behalf of other PCIA-eligible LSEs.

a VAMO sales framework for Local RA. By avoiding the need to sell capacity multiple years forward, which would create complexities due to changing LSE peak-load shares and cost responsibilities, the Local RA allocation mechanism better manages potential impacts of future customer migration.

The Co-Chairs acknowledge that the Local RA allocation proposal is less flexible for LSEs. However, due to the unique conditions in the Local RA markets, as noted above, the Co-Chairs felt this was the best path forward to ensure equity and cost sharing. The proposal also addresses LSEs' desire to monetize any PCIA-eligible Local RA by making Local RA allocations tradeable in the secondary market.

b) VAMO is Reasonable

The Co-Chairs propose that the VAMO for System and Flex RA provides an equitable means by which LSEs can elect to either receive their share of PCIA-eligible System and Flex RA directly or have customers receive economic consideration through PCIA rates. The Co-Chairs chose the VAMO structure for System and Flex RA due in large part to the challenges presented by Buffers, uncertainty tranches, and sales timing encountered with the Excess Sales approach, as discussed above. Additionally, utilizing the VAMO approach is designed to help keep PCIA rates approximately where they are today, while permitting LSEs the flexibility to manage their procurement activities by choosing the volume of the IOUs' RA attributes to procure at the MPB through an allocation. The multiple sales offerings considered by the Co-Chairs will provide adequate liquidity to the market.

c) System and Flex RA Market Offer Process is Reasonable

The proposed System and Flex RA Market Offer process comports with existing IOU standards and requirements for conducting solicitations. The valuation and selection process also comports with existing mechanisms, and is reasonable for eliminating potential conflicts of interest or questions around IOUs' decision-making and judgement in administering the Market Offer process. Additionally, the use of an IE and consultation with the CAM group, provides transparency and protections for the PCIA-eligible LSEs that the IOUs are fairly and reasonably conducting the Market Offer process, and in accordance with the approved requirements and timelines.

It is reasonable to permit the IOUs (on behalf of their customers) to participate in the Market Offer process provided ethical walls or advance bid protections exist and are monitored by the IE. The IOUs' participation is expected to promote greater competition for RA capacity, and is thus expected to lead to greater value realization in the Market Offer, which will aid in reducing PCIA rates. The protections will ensure that the IOUs are not granted an advantage, as compared to other market participants, in the Market Offer process.

It is reasonable that the System and Flex RA sold in the Market Offer process is offered only for the prompt year, as the System and Flex RA compliance requirements exist only on a year-ahead and month-ahead basis. This will preserve the System and Flex RA positions for equitable allocation each year on the basis of the latest forecasts of load shares. Allowing multiple RA contract term lengths within the Market Offer, between one calendar month and one calendar year, allows maximum value to be realized for customers by permitting greater flexibility for buyers to meet their needs through submittal of offers for strips of time that comport with their specific needs.

Establishing the spring Market Offer allows LSEs to fill a portion of their RA procurement volumes well in advance of compliance deadlines, and in doing so, is expected to increase the likelihood that System and Flex RA will be sold, and may result in higher System and Flex RA revenues, which would reduce PCIA rates. It is also reasonable to re-allocate unsold RA capacity to all LSEs, as all LSEs' customers are paying the above market costs in their PCIA rates.

d) <u>PCIA Showing is Reasonable</u>

The PCIA Showing provides a simple mechanism by which IOUs can provide PCIA-eligible LSEs with their share of RA and is already proven to work by example of the CAM showing mechanism. The PCIA Showing avoids the need by the IOUs to pick and choose from which resources to allocate RA attributes to each individual PCIA-eligible LSE, as would be the case with traditional CAISO Resource ID designations. The PCIA Showing is a fair way of allocating resources, as it enables each LSE to get a share of each contracted resources' capacity, thus promoting indifference among LSEs. Aligning the PCIA Showing timeline with existing RA processes creates efficiencies and synergies by leveraging existing requirements and processes. Finally, having ED responsible for determining LSEs' forecasted, vintaged, monthly, peak-load shares and allocations of capacity should mitigate parties' concerns in the process.

The proposal to re-allocate Local RA capacity for years 2 and 3 within the calendar year following the first compliance year is reasonable. LSEs' RA obligations change year over year in response to their forecasted peak load shares, so it is only fair that their allocations change in a similar manner. Similarly, LSEs' customers' relative cost shares also change year-over-year in their PCIA rates as load migrates between LSEs, so adjusting the allocation shares annually is fair and reasonable. Finally, the amount of capacity available for allocation may change as a result of the IOUs' portfolio optimization activities or adjustments to resources' NQC and EFC by the CAISO, thus necessitating a recalculation of the amount of capacity to be distributed to each PCIA-eligible LSE.

The Co-Chairs believe that the simplification of the PCIA RA allocation process by excluding intra-year load migration adjustments appears to be reasonable, as the actual amounts of intra-year load migration are likely *de minimis* and customers will be fully compensated by the proposed ratemaking mechanisms. The Co-Chairs propose that ED review the matter and issue a report after two years of RA allocations have taken place to evaluate the impact that this simplification may have for ensuring indifference.

e) Substitution and Substitution Cost Recovery is Reasonable

Requiring the IOUs to conduct substitution or other RA procurement to comply with all CPUC and CAISO requirements associated with the PCIA Showing and to charge the PABA vintaged sub-accounts for all costs, including penalties, simplifies the PCIA Showing process for PCIA-eligible LSEs and removes the need for non-IOU LSEs to conduct their own substitution. This is a proven method, as CAM has a similar substitution requirement and follows the same general cost-recovery principles as proposed by the Co-Chairs. Cost recovery through the PCIA for portfolio management costs required to comply with CPUC and CAISO regulations, including substitution activities and costs incurred due to the inability to procure substitution and penalties or costs associated with outage cancellations, is appropriate because it maintains customer indifference and follows the current CAM process.

f) Trading of RA Allocations is Reasonable

Trades or sales of LSEs' allocated RA enables LSEs to manage and monetize their portfolios and act in the best interest of their customers. This is particularly important for Local RA, which does not implement a Market Offer process. Additionally, this option may permit LSEs to sell their share of the PCIA Showing without having to sell other procured RA positions, which may be contractually restricted from re-sales. This flexibility to sell a share of the PCIA Showing RA reduces the risk of stranding RA with an LSE who is long, in which case that PCIA-eligible RA, or the RA it is displacing in the LSE's supply plan, may be used for less valuable purposes, such as using Local RA to meet System or Flexible RA showing requirements, or simply remain unutilized. The secondary trading of RA credit may increase the complication and administrative burden, however, the Co-Chairs believe this can be implemented in a manner that minimizes impact.

4. Non-Consensus Proposals

SCE and CalCCA propose that LSEs may not decline their Local RA allocation and there will be no Market Offer process for Local RA. Commercial supports a voluntary allocation of Local RA followed by a Market Offer of any unallocated Local RA.

C. GHG-Free Energy Voluntary Allocation

1. Background on GHG-Free Energy

The Co-Chairs' proposal for GHG-free energy relates to the allocation of energy, and its associated attributes, being generated by the IOUs' PCIA-eligible, non-RPS-eligible, large hydroelectric and nuclear resources, as well as any other potential PCIA-eligible, non-RPS-eligible, GHG-free energy producing resources. The primary interest in pursuing allocations of

GHG-free energy is for showing GHG-free energy procurement on an LSE's PCL and for planning purposes in the IRP. The Commission declined to assign GHG-free energy any specific MPB "adder" in the PCIA formula, and thus GHG-free energy is treated the same as brown power in the PCIA formula, receiving credit according to the realized CAISO energy and ancillary services revenues.

2. Co-Chair Consensus Proposal

The Co-Chairs propose that the IOUs will annually provide a voluntary, all-or-nothing allocation of GHG-free energy from their PCIA-eligible nuclear and/or large hydroelectric (and any other GHG-free, non-RPS, PCIA-eligible) resources to all PCIA-eligible LSEs on an annual basis. The GHG-free energy will be bifurcated into two pools: a nuclear pool and a non-nuclear pool. LSEs may make an election via a signed confirmation, serving as a sales contract, to accept or decline either or both pools in its (or their) entirety prior to the start of the flow year, in order to preserve the bundled nature of the delivered energy. No partial elections will be permitted.

The GHG-free energy allocations will be distributed on the basis of the forecasted, vintaged, annual-load (MWh) share of the PCIA-eligible LSEs, multiplied by the actual GHG-free energy production realized from the IOU's PCIA-eligible resources in each pool over the course of the flow year. LSEs who decline their allocation for either pool will have their allocation share of that pool redistributed among LSEs who accepted their allocation according to their vintaged, annual load share among the LSEs accepting that pool's allocations.

The IOU or its contracted counterparties will remain as scheduling coordinator of the resources, as applicable, and the benefiting LSEs have no rights to specify how resources are scheduled. The IOUs will continue to follow the Commission's existing least-cost dispatch requirements in their scheduling of these resources (some of which are non-dispatchable), and will provide documentation to LSEs specifying the source, volumes, and hourly profile of the GHG-free energy deliveries. LSEs accepting their allocations may claim the GHG-free energy deliveries on their PCL, subject to approval by the CEC, and may claim credit toward Clean Net

Short ("CNS") procurement requirements in IRP based on the hourly generation profile of the vintaged portfolio. As required by D.18-10-019, no incremental value will be ascribed to the GHG-free energy in the PCIA rates relative to the brown power MPB and CAISO energy and ancillary services revenue true-up.

CalCCA and Commercial propose that the PCIA-eligible LSEs that accept their allocations of GHG-free energy may trade or sell such GHG-free energy, including the right to claim the benefits on PCL. Sales contracts shall not grant any dispatch or scheduling rights to any buyers. As mandated by CEC requirements, in order to qualify for the transfer of GHG-free energy on the PCL, LSEs will need to enter into contracts establishing forward transactions.

3. Rationale for Consensus Proposal

The IOUs' GHG-free energy resources were built many years ago and were procured and/or built on behalf of all customers. These GHG-free energy resources are being paid for through the PCIA and the energy revenues are being realized by PCIA-paying customers. Therefore, the Co-Chairs believe it is only fair that these attributes be voluntarily allocated, and PCIA-paying customers benefit from the energy deliveries on their LSEs' PCLs and in IRP. Certain LSEs are prohibited from supporting nuclear energy production, so the Co-Chairs aligned upon a voluntary allocation mechanism for GHG-free energy that splits the resources into two pools: nuclear and non-nuclear, with LSEs able to elect from which (if either) pools to accept an energy allocation.

The re-allocation of unallocated GHG-free energy resources ensures an efficient distribution of clean energy across LSEs who wish to count such attributes on their PCL. The Co-Chairs believe that it does not make sense to have a Market Offer process for GHG-free energy because it is not a compliance product and does not have a market benchmark "adder" value.

D. Renewables Portfolio Standard Energy Voluntary Allocation & Market Offer

1. Background on Renewables Portfolio Standard Energy

The Renewables Portfolio Standard is California's overarching program for advancing renewable energy. The program established minimum requirements for LSEs to procure electricity from eligible renewable energy resources, certified by the CEC. LSEs must demonstrate their RPS compliance over the course of certain pre-defined three- to four-year long compliance periods that permit annual under- or over-procurement variations, provided the LSE meets its compliance period RPS procurement requirement. Senate Bill 350 requires LSEs to enter into ownership or contractual arrangements of 10 years or longer for eligible renewable resources for 65 percent of their procurement quantity requirements for all compliance periods beginning January 1, 2021.[32]

To evidence procurement of RPS generation, LSEs are required to retire Renewable Energy Credits ("RECs"), which are certified by the Western Renewable Generation Information System ("WREGIS"). LSEs are also required pursuant to RPS rules to procure RPS generation resources corresponding to certain categories, known as Portfolio Content Categories ("PCC"), which set limits on the minimum or maximum energy that LSEs may procure from specific resource types.

LSEs with an excess of RECs in a given RPS compliance period may choose to "bank" their RECs for future use. When an LSE uses this bank of RECs for its own purpose, the banked RECs retain their original PCC status and provide credit towards RPS compliance requirements, but the LSE receives no PCL credit, as the energy had already been delivered in the past. However, when an LSE sells a REC after the energy has been delivered, that REC counts only as an unbundled, PCC3 REC, and thus may lose value relative to its value if the REC holder were to use it.

2. <u>Co-Chair Consensus Proposal</u>

[32] SB 350.

a) Overview of RPS VAMO Proposal

The Co-Chairs propose that the IOUs' PCIA-eligible RPS energy be subject to an annual, voluntary allocation among all PCIA-eligible LSEs on the basis of their forecasted, vintaged, annual load (MWh) shares and the actual, vintaged, annual RPS energy production. Any unallocated RPS energy is to be made available for sale through an annual Market Offer process to be held by the IOU prior to the Delivery Year.

Regardless of allocation or sale, the IOU or its contracted counterparties, as applicable, will remain as the scheduling coordinator(s) of the RPS resources. Benefiting LSEs have no rights to specify how resources are to be scheduled, and the IOUs will continue to follow existing least-cost dispatch. Both allocations and Market Offer sales will convey rights to RECs and PCL reporting, and will be structured as forward contracts that preserve the bundled nature of the RPS energy and the PCC status from the IOU's underlying contracts. PCIA-eligible LSEs will additionally be eligible to claim their forecasted RPS energy allocations in the IRP process in proportion to the hourly generation from the IOU's vintaged RPS portfolio from which the allocations are sourced. However, only long-term allocations or sales convey rights to credit for long-term RPS procurement requirements.

b) RPS Energy Allocation Options

The Co-Chairs propose that during the annual RPS allocation election process, LSEs may elect to take a short-term allocation, a long-term allocation, or may choose to decline all or a portion of their allocation; each election to be made in 10 percent increments of the LSE's forecasted annual load share. Short term allocations will have a term of one calendar year. Long-term allocations will last through the end of the term of the longest contract in the particular PCIA vintage (excluding the term associated with utility-owned generation ("UOG") and evergreen contracts (*i.e.,* legacy Qualifying Facility contracts with contract terms that do not expire)). Once accepted, the LSE may not decline its long-term allocation election in future years, but may increase its election within future election opportunities, provided at least 10 years remain on the term of the longest-dated contract in the vintage. An LSE's long-term allocation election will be set at a fixed percentage of its forecasted, vintaged, annual load share, but both the LSE's forecasted vintaged, annual load shares and the RPS energy deliveries will change from year to year based on the updated forecasts of vintaged, annual loads and the actual RPS energy volumes realized in each year of the allocation term. LSEs that accept allocated RPS energy may choose to re-sell such allocated RPS energy outside of the VAMO process. For an example of how short-term and long-term allocations will work, refer to Appendix I.

The Co-Chairs propose that LSEs electing long-term allocations will receive long-term RPS credit, provided that, at the time of election, the longest remaining non-UOG or evergreen contract within the LSE's vintage has at least ten years remaining on its term. Additionally, LSEs will only receive long-term credit for the allocated RPS energy if the IOU's original contract was at least 10 years in term.

Certain PCIA-eligible LSEs' customers may have departed many years ago, and therefore those LSEs may be ineligible to ever participate in the IOUs' long-term allocations, if less than ten years remain on any contract in their PCIA vintage as of the RPS VAMO implementation date. However, because the IOUs' contracts were originally procured on behalf of these bundled service customers, and these customers have continued to bear cost responsibility through the PCIA, the Co-Chairs propose that, in the first election period only, if the remaining term of the longest, non-evergreen contract or UOG life within an LSE's PCIA vintage is less than ten years, then the LSE will be grandfathered to receive the same long-term credit for the allocated RPS energy as the IOU would have received from those contracts within its portfolio, provided at least one contract in the vintage had a term of at least 10 years in length. This will prevent the destruction of value from the long-term RPS attributes that rightfully should belong to these customers. The Co-Chairs agree that this grandfathering proposal should not apply to sales or other allocation approaches outside of PCIA, as this is a unique situation that resulted from the IOUs' mandates to procure RPS generation as ordered by the state, and in their role as the primary energy service providers in the state at the time of such procurement. Further, PCIA represents a unique situation in that all of these customers remain customers of the IOU through the provision of transmission and distribution services.

c) RPS Energy Market Offer Process

The Co-Chairs propose that all unallocated RPS energy for the prompt year will be offered for sale through an annual Market Offer process to be held by the IOU. Within those unallocated volumes, the IOUs will offer up to 35 percent of each LSEs' annual declined allocation share as long-term sales, not to exceed 35 percent of that LSE's total forecasted allocation share for the remaining term of the PCIA. Long-term sales will be offered for terms ranging from 10 years to the life of relevant PCIA vintages. SCE proposes that long-term sales should be structured so as to convey a percentage slice of the unallocated RPS portfolio vintages. The balance of unallocated RPS energy is to be offered for sale with a one-year term beginning on January 1 following the Market Offer. For an example of how the long-term sales threshold determination works, refer to Appendix H in Tables 28 and 29.

The Co-Chairs propose that the Market Offer process will be conducted using Commission pre-approved mechanisms for the solicitation's administration, valuation, selection, and contracting, which will be approved via each IOU's submittal of updates to its RPS Procurement Plan. Additionally, an IE will monitor the solicitation and the CAM group will be consulted on offer selections. The Market Offer process will be open to all market participants, including the IOU holding the market offer process. If the IOU is participating in its own market offer, the IOU must (i) submit bids to the IE and ED in advance of the Market Offer launch or (ii) establish dual procurement teams separated by an ethical wall, with monitoring by the IE to ensure a fair and non-preferential process. Additionally, the Co-Chairs propose that ED compile an annual report following the completion of the IOUs' Market Offer solicitations, which will summarize the results of the auctions and the potential impact that the cap on long-term sales had on realized RPS energy market value. The Co-Chairs propose that the long-term sales cap be re-evaluated after two years to determine whether it should be adjusted.

The Co-Chairs propose that all contract pricing be structured through a flat (*i.e.*, no annual escalation) index + REC price transaction structure. Each IOU will choose which contract type it will use for the Market Offer, which will include slice-of-generation contracts in which deliveries are contingent upon the actual amount of generation within the RPS portfolio and offer an hourly delivery profile consistent with the profile of the IOU's aggregate, declined RPS allocations. Parties purchasing RPS energy through the Market Offer process will receive the RECs, the ability to claim the energy on their PCL, and if entering into a long-term contract, the right to claim the RPS energy in the IRP process based on the hourly generation profile of the unallocated RPS portfolio from which the sale is sourced and receive long-term contracting credit for RPS compliance. To protect PCIA-paying customers against defaults, the IOUs will require appropriate credit, collateral, netting agreement terms, or other commercial arrangements.

The Co-Chairs propose that the valuation and selection process for the Market Offer must be transparent and limit discretion by the IOUs, as to not have LSEs question the rationale for the selections. The Co-Chairs propose that the Market Offer process evaluate bids based solely on the highest price offered, with no discount rate applied to valuation of long-term sales, and that the IOUs select offers in merit order until all unallocated RPS energy has been sold (subject to the long-term sales cap described above).

In the event that unsold RPS energy remains after the conclusion of the Market Offer process, the unsold RPS energy volumes will be re-distributed among all LSEs at no cost and on a pro-rata basis according to their forecasted, vintaged, annual load shares. The re-allocated RPS energy attributes will be treated as sales at $0/MWh and will be reported, along with the volumes re-allocated, by the IOUs to ED for the purposes of establishing the RPS MPB. This treatment ensures parties that declined allocations get the benefits of the RPS energy for their own use or re-sale, and ensures parties taking allocations are not unfairly impacted.

On a monthly basis throughout the flow year, the IOUs will calculate the allocated quantity of RPS energy delivered to each LSE and charge those LSEs for their allocated volumes as described more fully in Section V.H.2. Within 120 days following the end of each flow month, the IOUs will convey the RECs to buyers from the Market Offer and to LSEs that have elected to take allocations.[33]

3. Rationale for Consensus Proposal

a) VAMO is Reasonable

The Co-Chairs propose that the RPS VAMO mechanism provides an equitable means by which LSEs can elect to receive RPS energy directly as an allocation, have their customers receive economic consideration through PCIA rates, or choose a blend of the two options to suit their specific needs. Additionally, in the interest of protecting customer value, the Co-Chairs have developed mechanisms to enable the sale and/or allocation of long-term RPS attributes and preserve the RPS energy's REC, PCL, CNS, and PCC attributes, which can be transferred through allocations or sales. However, to remain consistent with existing statute, the preservation of long-term RPS attributes will require long-term commitments, as discussed below.

b) Long-Term Allocation Proposals are Reasonable

The Co-Chairs have developed a proposal for the treatment of allocations and sales that is compliant with existing statutory requirements for the preservation of long-term RPS credit. This proposed mechanism, wherein a long-term allocation must last for at least 10 years and through the end of the term of the longest contract in the PCIA vintage, with the exception of evergreen contracts and UOG resources, is reasonable as it reduces the risk that attributes will be stranded in the future. The proposed exclusion of UOG and evergreen resources is reasonable as LSEs could otherwise be bound indefinitely to take RPS energy from the IOUs through allocations, which would inhibit LSE procurement flexibility. The Co-Chairs suggest that the grandfathering proposal for long-term allocation elections made in the first election period is reasonable, as it permits certain LSEs who might otherwise be excluded from long-term RPS

---

[33] RECs are created within 90 days, so this is 30 days from REC creation.

treatment because they departed from the IOU many years ago, to realize the long-term RPS value that was procured on behalf of their customers. The Co-Chairs do not believe that this grandfathering proposal should be precedential in any other setting, as the PCIA is unique in its treatment of the IOUs' historically mandated procurement.

c) Market Offer Proposal is Reasonable

The Market Offer process proposed by the Co-Chairs is reasonable as it comports with existing IOU standards and requirements for conducting solicitations. The contract pricing requirements are reasonable for eliminating potential conflicts of interest or questions around IOUs' decision-making and judgement in administering the Market Offer processes. Monitoring by an IE and consultation on offer selections with the CAM group provides transparency and protections for other LSEs to ensure that IOUs are fairly and reasonably conducting the Market Offer process. The Co-Chairs propose the use of the CAM group (rather than Peer Review Group ("PRG")) for review of the PCIA Market Offer results with the expectation that CCAs and other PCIA-eligible LSEs would be eligible to join the CAM group by hiring independent, non-market participants as their proxies and be subject to rules governing market sensitive information.

It is reasonable to permit the IOUs to participate in their own Market Offer process, provided ethical walls or advance bid protections exist and are monitored by IE. The IOUs' participation allows for greater competition for RPS energy and thus maximizes value realized in the Market Offer, which will aid in reducing PCIA rates for all customers. Additionally, it affords IOUs the same opportunity as any other market participant to procure RPS energy that is declined by PCIA-eligible LSEs, thus permitting the IOUs to advance their clean energy goals on behalf of bundled service customers. The proposed protections will ensure that the IOUs' participation in the Market Offer does not grant them an undue advantage relative to other market participants.

The Co-Chairs suggest that it is reasonable to cap long-term sales, initially at 35 percent. Such a cap will help prevent issues that could arise when load migration, coupled with greater long-term sales volumes and portfolio optimization activities, may cause challenges for the IOUs to fulfill the volumes required to meet each LSEs' eligible allocation share. The Co-Chairs recommend that ED review the long-term sales cap after two years to ensure that it is not overly limiting.

The Co-Chairs propose that it is reasonable for the IOUs to evaluate the appropriate mix of RPS contract types to make available for sale in the Market Offer to protect the ability to fairly allocate attributes across LSEs, while maximizing customer value. Each IOU's portfolio is composed of different resources and technologies, and thus may require different RPS contract types to balance allocations against Market Offer sales.

Additionally, it is reasonable to require credit, collateral, netting agreements, or other similar commercial arrangements to prevent defaults from raising costs for all customers. If an LSE fails to pay for delivered RPS energy, the IOU could refuse to deliver the RECs corresponding to such uncompensated energy. However, the RECs following that RPS energy would be de-valued from PCC1 to PCC3, as they would no longer be bundled with the energy, since the resources would have already generated such energy. Without appropriate collateral, the buyer's failure to pay would destroy customer value without recourse, leading to higher PCIA rates.

Finally, it is reasonable to re-allocate unsold RPS energy to LSEs that chose to sell, as the attributes were procured originally on behalf of their customers and those customers should realize the value associated therewith. If the LSEs are allocated the unsold RPS energy, they may thereafter seek to monetize those attributes themselves to realize value for their customers.

E. <u>GHG Emissions from PCIA Resources</u>

1. <u>Co-Chair Consensus Proposal</u>

The Co-Chairs propose that the treatment of the IOUs' PCIA-eligible, GHG-emitting resources be dealt with in the same fashion as the IOUs' CAM-eligible, GHG-emitting resources are treated on the PCL. The CEC now requires IOUs to report only their bundled load share of the emissions resulting from the dispatch of GHG-emitting CAM resources. The balance of the energy dispatched, and its resultant emissions, is treated as unspecified power within the state of California. Any LSE, other than the contracting IOU, whose customers pay for the procured CAM resources is not directly attributed the GHG emissions resulting from their proportional share of output from the CAM resources, but instead shows unspecified power on the PCL to the extent that any retail sales are not accounted for with procurement contracts. The emissions factor associated with this unspecified power procured from the CAISO market incorporates the emissions resulting from the share of the CAM resources that is not attributed to the IOUs' bundled load customers.

The Co-Chairs propose that the Commission request that the CEC explore expanding the current regulations pertaining to CAM resources to also include PCIA resources. However, one distinction for the PCIA resources relative to CAM resources would be that the determination of the share attributable to the bundled load customers should not be based upon the CAM load share, but rather should be based upon the IOU's actual, vintaged annual load (MWh) share of the energy generated by the PCIA-eligible, GHG-emitting resources. This emissions allocation methodology aligns with the concepts put forth for the allocation of GHG-free energy and RPS energy and is an equitable mechanism for showing the energy intensity associated with serving bundled service customers from their share of the PCIA portfolio.

2. <u>Rationale for Proposal</u>

The proposal to have the IOUs show only their vintaged load share of the emissions relating to the PCIA-eligible, GHG-emitting resources is reasonable as it creates an equitable means of demonstrating the energy intensity associated with serving bundled service customers. The proposal also aligns with the existing precedent set by the CEC's implementation of new regulations pursuant to AB 1110 for treatment of the emissions relating to CAM resources. Allowing the IOUs to only report the bundled service load's vintaged share of such energy on the PCL is a more equitable manner for treating the GHG emissions from PCIA resources.

F. <u>Allocation Forecasting</u>

While touched upon above, in the interest of articulating the specific mechanisms proposed for the determination of allocation shares, the Co-Chairs lay out the specific forecasting steps below.

1. **Co-Chair Consensus Allocation Methodology**

a) Vintaged Load Shares

The Co-Chairs propose that the forecasts to be used for determining each PCIA-eligible LSE's allocation load shares will be the load forecasts for the upcoming calendar year that are submitted to and calibrated by the CEC and CPUC pursuant to the existing RA process. However, to account for the vintaged nature of the PCIA mechanism, the Co-Chairs propose to add the requirement for LSEs to provide their historical load information and load forecasts pertaining to each month and each vintage (i.e. each year of departure) of customers that departed from IOU bundled service. New processes and load forecasting methodologies will need to be developed to calibrate LSE's vintaged, monthly coincident-peak- (MW) and annual- (MWh) load shares, analogous to the calibration that takes place today to determine the forecasted, monthly, coincident-peak-load for California and to fairly allocate the RA procurement requirement across all LSEs. In July, following the load forecast calibration, ED will send a letter to each LSE indicating its preliminary vintaged, monthly, coincident peak-load (MW) share and vintaged, annual load (MWh) share, which can be used to inform each LSE of their estimated allocation of PCIA-eligible RA capacity and RPS and GHG-free energy, respectively. In September, the ED will send another letter to each LSE updating these published calculations to reflect the final allocation volumes that each LSE would be eligible to receive. For examples demonstrating how vintaged peak-load and annual load share determinations work, refer to Appendix H in Tables 2 to 5.

b) Vintaged Product Positions

The IOUs will be required to provide PCIA-eligible LSEs with an indicative, vintaged PCIA-eligible RA position forecast in April to aid in their portfolio planning and procurement activities. However, the final, total capacity that is to be allocated among all PCIA-eligible LSEs will be equal to each IOU's monthly PCIA-eligible Local and System and Flex RA capacity available as of the CAM capacity filing deadline in July, as further adjusted for any modifications by the CAISO to the resources' NQC or EFC in the final NQC/EFC publication, which currently is published in late September, except as provided below with respect to use-limited resources. This final, monthly total quantity of capacity for each type of RA will be shown by the IOU and will be used by ED to determine the actual PCIA capacity available for allocation to each LSE.

With respect to use-limited resources, the total capacity available for allocation may be reduced by the IOUs on the basis of forecasts for the particular facility, provided (1) the IOU justifies the difference in capacity value in workpapers, or otherwise, submitted in the ERRA Forecast of Operations application, and (2) if the IOU later identifies that additional capacity is available for RA purposes, the IOU may (a) use such capacity for substitution relating to the PCIA Showing, (b) re-allocate such capacity to PCIA-eligible LSEs at $0/kW-mo cost, or (c) sell the capacity with revenues flowing to the resource's vintaged PABA sub-account.

For RPS and GHG-free energy, the actual deliveries are contingent upon the actual hourly production of the resources in each vintage over the course of the calendar year, including any IOU portfolio optimization activities. For examples showing how the allocation and re-allocation would work for each product pool, refer to Appendix H.

2. <u>Rationale for Consensus Proposal</u>

a) <u>Proposed Allocation Methodology is Reasonable</u>

The Co-Chairs submit that the proposed allocation methodology is a fair and equitable mechanism for distributing PCIA-eligible products to LSEs serving PCIA-paying customers. For RA, the application of the forecasted, vintaged, monthly, coincident peak-load (MW) share as identified through the RA process best reflects the actual RA obligation shares of each LSE and aligns cleanly with existing RA processes, while providing RA position stability to LSEs accepting their allocations throughout the course of the year. Similarly, for RPS energy and GHG-free energy, using the forecasted, vintaged, annual load (MWh) share best reflects the actual requirements needed to serve each LSE's customers and provides more certainty about the volumes to be received. Further, allocating the products on a vintaged basis aligns the distribution of the products with the customers for whom they were procured, and thus allocates value equitably to those customers who are paying for the costs of such contracts or UOG resources. It is also reasonable to use 10 percent allocation election increments to allow LSE optionality while preventing undue administrative burden in tracking LSE elections. This optionality allows LSEs to manage their procurement more freely by enabling customized solutions composed of a mix of allocated RPS energy and credits realized in PCIA rates.

The Co-Chairs explored using a cost-share mechanism for allocation of RA and energy attributes but identified challenges in being able to accurately forecast LSEs' cost-shares. When taken together, utilizing a peak-load (MW) share for RA and an annual load (MWh) share for RPS and GHG-free energy approximates LSEs' customers' cost responsibilities relating to capacity and energy procurement, as these capacity, RPS, and energy procurement costs are factored into each customer segment's PCIA rate allocation factors.

Allocating the PCIA-eligible RA position volumes as of the July CAM capacity filing, as further adjusted for changes by the CAISO to the resources' NQC or EFC, is reasonable. The timing for finalizing the allocation volumes allows the IOUs to conduct portfolio optimization with the objective of maximizing customer value, while freezing the allocation volumes early enough for PCIA-eligible LSEs to have an understanding of how much credit they will receive through the PCIA Showing so they can act to procure their residual RA positions in the market. Further, freezing the allocation amounts ensures that parties will not end up short at the year-ahead showing or thereafter due to the IOUs' portfolio optimization actions. Efficiencies are gained by leveraging the existing CAM process for the IOU to publish the volumes available for allocation.

Allocating RPS and GHG-free energy on the basis of the actual deliveries is also reasonable, as it ensures that all RPS and GHG-free energy is accounted for and fairly distributed among the PCIA-eligible LSEs. This also permits the IOUs to continue to pursue portfolio optimization opportunities throughout the flow year, which is reasonable, as it permits the IOUs to maximize the value of the portfolio. Additionally, aligning with the RA process helps mitigate potential gaming by LSEs to receive greater RPS allocation volumes because higher load forecasts, while not perfectly correlated, could result in higher peak-load forecasts, thus causing higher RA procurement obligations.

G. RPS and GHG-Free Energy Production Disclosures

1. Co-Chair Consensus Proposal

The Co-Chairs have agreed upon certain confidential, forecasted and actual generation information pertaining to the RPS and GHG-free energy portfolio that the IOUs will provide to PCIA-eligible LSEs to enable them to conduct portfolio planning, subject to execution of a Non-Disclosure Agreement ("NDA") acceptable to the IOU by the PCIA-eligible LSE. The IOUs will provide (a) the most recent three years of historical, aggregated, hourly production data by RPS, nuclear, and/or non-nuclear pool; (b) the CAISO resource identifications for all resources in each pool; and (c) the following forecasts of aggregated production data by vintaged pool:

1. Aggregated, total year-ahead ERRA forecast;
2. Aggregated, year-ahead ERRA forecast of the total production for each of the 12 months; and
3. Quarterly updates for remaining balance of year of the monthly total, aggregated production.

The forecast will be provided as is, without any warranty. If aggregation is not possible, the IOUs will provide the pools' production information on a historical basis only. Aggregations will require at least five (5) resources, unless the IOU waives such requirement, which shall not be construed to establish precedent for future aggregations.

2. Rationale for Consensus Proposal

CalCCA and Commercial requested, and SCE is willing to provide, sufficient information on the RPS and GHG-free energy allocations for PCIA-eligible LSEs to properly perform their procurement planning activities. However, in the interest of protecting market sensitive information, the IOUs must protect confidential information, such as unit-specific production amounts and planned outages. The Co-Chairs believe that they have proposed sufficient information to be exchanged under NDA to permit LSEs to perform their procurement planning and for the CEC to conduct its audits, as necessary, for verification of PCL reporting.

H. Proposals for Modifications to PCIA Ratemaking

1. Background on Ratemaking Decision in Working Group 1

The PCIA calculation is a product of decisions dating back to 2002, with its most recent formulation adopted in D.18-10-019 and D.19-10-001. In its simplest form, the PCIA calculation can be shown as follows:

While the WG 3 proposals will not affect portfolio costs or billing determinants, the proposals require modification of the portfolio value that is offset against costs to determine the indifference amount.

The final portfolio value, today, is calculated as the value of the resources retained in the bundled utility portfolio plus the value obtained in the market for resources in excess of bundled requirements. The bundled portfolio value is determined as (1) the Local, System, and Flexible RA capacity and RPS energy retained for bundled service customer load (i.e., not offered for sale to the market) multiplied by the respective MPBs for each product plus (2) the value received in the market for the sale of energy and ancillary services; Local, System, and/or Flexible RA capacity; and RPS energy. The portfolio value is forecasted in each IOU’s ERRA Forecast of Operations application before the start of a PCIA rate year and is then subject to a true-up in the November Update to ERRA Forecast application, with any over- or under-collection recovered in rates the following year. All elements of the calculation are subject to true-up, including load, generation, sales revenues, and MPBs. Costs and revenues are charged and credited on a vintaged basis to the PABA's vintage-specific sub-accounts, with departing load customers responsible for the net costs realized from their vintage and prior through their PCIA rates.

A cap of $0.005/kWh was established for the maximum PCIA rate rise permissible year-over-year, with a 10 percent under-collection trigger threshold established. If an IOU were to reach a 7 percent under-collection as the result of capped PCIA rates, the IOU would be required to file an application with the CPUC proposing a revised PCIA rate to bring the projected under-collection balance below 7 percent for the remainder of the calendar year.[34]

2. Co-Chair Consensus Proposal

The Co-Chairs propose using the existing PCIA framework and benchmarks to implement the consensus allocation-based approaches with certain modifications:

- All Local RA attributes will be valued at $0/kW-mo for PCIA ratemaking. Because all LSEs will receive Local RA attributes in accordance with their pro-rata share, no offset of the MPB against the full costs of Local RA is required in the PCIA formula.
- The Co-Chairs propose that in the year the change in cost-recovery treatment for the Local RA allocation is implemented, the Commission should authorize the IOUs to exclude the additional revenue requirement from the PCIA rate cap adopted in D.18-10-019 to account for this change. This exclusion would only apply to the first year the Local RA allocation is implemented, to reduce the risk that the change will cause the IOUs to trigger the PCIA cap.
- Regardless of whether LSEs accept or decline their allocations, the GHG-free energy will continue to receive the brown power MPB for the purposes of setting forecast rates and realized CAISO market revenue true-up in PCIA calculation as an offset against total costs.

[34] Alternatively, an IOU is authorized to notify the Commission through an advice letter submittal, instead of an expedited application, when the IOU reasonably believes that the balance will self-correct below the trigger point within 120 days of the submittal.

- System and Flex RA and RPS energy allocations will be treated like sales in the existing framework. LSEs electing to accept allocations will be required to pay the IOU the applicable year's MPB for the attributes received and may be required to meet certain credit or collateral requirements, netting agreements or other commercial arrangements. These payments will be recorded in PABA and will offset costs in the PCIA. IOUs will also be required to pay for their allocations via a debit from the ERRA balancing account and a credit to PABA.
- Any sales revenues from Market Offer processes will also be recorded in PABA, in a similar manner to how sales are recorded today, although the accounting for sales revenues will need to account for the vintages of the LSEs that declined their allocations by allocating revenues pro rata across vintages in proportion to the declined volumes in each vintage.
- Unsold System and Flex RA attributes and RPS energy will be allocated at no cost to all PCIA-eligible LSEs on the basis of their forecasted, vintaged, peak- and annual-load shares.
- The methodology for calculating the MPB for System and Flex RA and RPS energy developed in the Phase 2, Track 1 process of R.17-06-026 will be retained, but will be updated to incorporate the unsold, re-allocated volumes at $0 into the determination of the MPB values.

Under this proposed implementation, the existing ratemaking construct adopted by D.19-10-001 has not changed substantially. Net costs to be recovered through PCIA rates are to be determined according to the following formula:

Total Contract and UOG Costs[35]

(-) CAISO revenues

(-) Product sales revenues

---

[35] Including costs to substitute or mitigate availability risks, as discussed in Section V.B.2.g.

(-) Quantity of products allocated multiplied by PCIA attribute MPB

(+) under-collected amounts or (-) over-collected amounts in PABA and/or the PCIA undercollection balancing account ("PUBA")

= Net Above Market Costs

Refer to Appendix H in Tables 56 to 59 for examples of how the ratemaking mechanism works for each product type.

3. **Rationale for Consensus Proposal**

During the WG 3 discussions, the Co-Chairs discussed two ratemaking options.

SCE and Commercial initially proposed an alternative approach whereby PCIA rates receive a $0 value for each attribute (*i.e.,* eliminate the MPB for each product), thus resulting in full cost recovery through PCIA rates for each product contemplated in the VAMO process. Then, to realize the economic value directly associated with unallocated attributes sold in the Market Offer, LSEs would receive a payment directly from the IOU associated with the LSE's share of such sales revenues. This proposal became known as Ratemaking Option 1 in the Co-Chair discussions and in the workshop presentations. While SCE and Commercial agree that this approach has some advantages, one disadvantage with this approach is that, as the full contract costs would be recovered through the PCIA rate with no offsetting attribute values, the PCIA rates would increase relative to today's PCIA rates.

CalCCA had concerns over Ratemaking Option 1, as it could lead to dramatically higher PCIA rates. CalCCA instead advocated for Ratemaking Option 2, which the Co-Chairs ultimately reached consensus upon for the System and Flex RA and RPS energy VAMO proposals. This proposal also received general consensus among stakeholders at the Third Workshop and in informal comments received. Ratemaking Option 2 preserves the existing framework established by D.18-10-019 but expands eligibility for purchases of attributes at the MPB to all PCIA-eligible LSEs on the basis of their allocation shares.

The Co-Chairs aligned upon valuing Local RA at $0/kW-mo as all LSEs will receive their share of the Local RA attributes, and there are no sales to be performed to credit against

PCIA costs. Eliminating the MPB simplifies cost recovery and ensures full costs are recovered. A consequence of eliminating the MPB associated with Local RA is that PCIA rates may rise. In this case, the Co-Chairs recognize that this increase in PCIA rates is accompanied with an allocation of attributes that provides a concrete benefit associated with the increased cost, and justifies a one-time adjustment to the PCIA rate cap to exclude the impacts of this change in the Local RA MPB methodology.

No changes are proposed to GHG-free energy cost recovery, regardless of whether LSEs accept or decline allocations, as customers already receive the full costs and benefits associated with the nuclear and non-nuclear GHG-free resources economically through rates.

Reallocating unsold System and Flex RA and RPS energy at no cost to LSEs ensures that all LSEs receive the value associated with the unsold attributes. Those LSEs can choose to use the unsold volumes for their own compliance purposes or may choose to sell the attributes in the secondary market themselves. The unsold attributes should be incorporated into the MPB to ensure that the MPB appropriately reflects the market value of the attributes, which permits more equitable treatment between LSEs receiving unsold attributes and those LSEs that must pay the MPB for allocated attributes.

Examples of how the ratemaking mechanisms for each product type, and how Ratemaking Option 1 and Ratemaking Option 2 compare are included in Appendix H, Tables 56 to 59. A graphic illustrating the difference in cost recovery is included in Appendix G.

I. <u>Co-Chair Proposal for Transfer of Attributes on PCL</u>

The Co-Chairs propose that allocations of RPS and GHG-free energy will be structured to comply with existing CEC requirements for PCL reporting. LSEs accepting allocations will be required to sign contracts or election confirmation forms indicating forward commitments to procure the allocated attributes. The bundled energy will be delivered by the IOU or its counterparties, as applicable, to the CAISO market. Following the flow year, the IOU will identify the sources and volumes of energy delivered to each LSE, which will permit the LSE to conduct its CEC reporting.

J. Treatment of PCIA Allocations and Sales within IRP

1. Co-Chair Consensus Proposal

The Co-Chairs propose that LSEs may receive IRP credit for their forecasted, vintaged load shares of the hourly generation of each allocated product from the IOUs' PCIA portfolios through the end of the term of their PCIA vintage(s). This proposal operates under the assumption that each LSE will, by default, accept its allocation within the context of IRP treatment, which is reasonable as the PCIA resources have already been contracted for by the IOUs on behalf of bundled and departed load customers, and, to a large extent, already reflect generating facilities that are in operation. Accordingly, if any LSE were to choose not to take its allocation for any given year, the amount of capacity and RPS or GHG-free energy in the system remains unchanged, as it is simply transferred to another entity, and does not alter the volumes of each product considered within the IRP's Reference System Plan ("RSP").

The short-term sales of RA and RPS energy through the Market Offer and the re-allocation of GHG-free energy will not convey long-term IRP credit to the buyers or LSEs receiving a re-allocation, as the term of such sales or re-allocations will be for only one year. However, for RPS energy, if an LSE elected to decline its allocation, and a portion of such allocation was sold long-term in the Market Offer process, then those RPS energy volumes sold long-term would (i) convey IRP credit to the buyer in the Market Offer process, (ii) be unavailable for the declining LSE to receive as an allocation in the future, and (iii) not be available to the declining LSE in IRP.

Appropriate procedures will need to be developed within the IRP OIR to provide LSEs IRP credit in accordance with the consensus proposals.

VI.

SCOPING ISSUE 2: STRUCTURES, PROCESSES, AND RULES GOVERNING PORTFOLIO OPTIMIZATION

A. Existing IOU Portfolio Optimization Activities

The IOUs aim to maximize their portfolios' value for customers by seeking out opportunities to reduce customer costs, when feasible, without sacrificing the integrity of their respective portfolios. Portfolio optimization activities require judgement, a consideration of current market conditions, adherence to policies and Commission rules, and negotiation with counterparties to be successful. Portfolio optimization activities are not intended to undermine or negate the original terms of the contracts without both parties' agreement. Further, the IOUs cannot unilaterally terminate a contract, unless events occur giving the IOU contractual rights to do so.

The opportunity to modify a contract typically arises under three circumstances: (i) either party requests a contract modification; (ii) buyer and seller identify an opportunity for a mutual benefit; or (iii) a counterparty fails to perform. When any of these circumstances occur, the IOUs may pursue a contract amendment, termination, buy-out, assignment or other action with an eye towards providing a net benefit to customers. The IOUs utilize a variety of tools to manage their portfolios and the contracts therein, including, but not limited to, sales of resources and/or attributes, collateral reductions, economic curtailment, capacity reductions, contract buy-outs and other modifications. The details surrounding these activities are included in the IOUs' respective annual ERRA Review of Operations applications.

The Co-Chairs propose that the IOUs may optimize their respective portfolios of RPS and GHG-free energy resources at any time, but if such activities affect the allocations for the Delivery Year, the IOU must provide at least 60 days' prior notice of the transaction to PCIA-eligible LSEs to indicate the potential impact on expected allocation deliveries. The Co-Chairs recognize that sizable portfolio optimization transactions could have a significant impact to expected LSE allocations in a Delivery Year. As such, the Co-Chairs propose that IOUs should not reduce the expected RPS or GHG-free energy portfolio deliveries by more than 10 percent in the Delivery Year, unless otherwise mandated by the Commission.[36] There would be no limitation on potential portfolio optimization activities that would impact allocations in future years.

Non-resource specific sales of PCIA-eligible attributes that are conducted for the overall PCIA portfolio will affect all LSEs proportionally, with the volumes deducted pro rata from all vintages, as today. Such sales will not be conducted within the Delivery Year. There would be no limitation on potential sales activities that would impact potential allocations in future years. However, like any other LSE receiving an allocation, the IOUs may sell their bundled load's share of forecasted allocation volumes of any attribute, provided they disclose prospectively that such sales would accrue only to the bundled load's position.

B. Proposed Portfolio Reduction Process

1. Background on Portfolio Reduction Process

In D.18-10-019, the Commission instituted Phase 2 to "offer the promise of meaningful progress toward reducing the levels of above-market costs going forward."[37] While the VAMO optimizes the allocation of resources and will generate revenues to offset PCIA costs, it does not seek to reduce IOUs' overall portfolio size. For this reason, and as directed by the Phase 2 Scoping Memo, the Co-Chairs explored other potential mechanisms to provide greater structure around and transparency into the IOUs' efforts to reduce their overall portfolio costs.

Reductions in total portfolio costs can be achieved by modifying or terminating existing contracts. The Co-Chairs reached alignment on potential means of reducing contract costs through, among other things, contract buy-outs or assignments, which would remove resources entirely from the portfolio. The Co-Chairs propose that this may occur by the IOUs reaching out to their counterparties to solicit interest in fully assigning their contracts to other LSEs.

---

[36] For purposes of this limitation, contract management actions taken directly under the contract, such as responding to an event of default or exercising a contract option, do not constitute portfolio optimization.

[37] D.18-10-019 at 129.

2. **Co-Chair Consensus Proposal for Portfolio Reduction**

a) Overview of Portfolio Reduction Proposals

The Co-Chairs propose that the IOUs will hold an RFI process with their RPS contract counterparties ("Sellers") for interest in two types of transactions: (i) a contract assignment or (ii) a termination that facilitates a re-contracting by the Seller to another LSE (both referred to herein as a "Contract Assignment"). The Co-Chairs propose that the RFI be conducted in 2021 and 2022 and every other year thereafter. Following the completion of the 2022 RFI, the Commission will determine the need for continuing to conduct the RFI every other year and consider any modifications to the RFI process. Additionally, the IOUs will solicit proposals for termination, buy-out, or amendment transactions unrelated to a Contract Assignment ("Contract Modifications").

b) Contract Assignment RFI Process

The Co-Chairs propose that the IOUs canvas their portfolio for Sellers interested in Contract Assignments. SCE proposes that in determining eligibility for this RFI, the IOUs may elect to exclude (i) contracts that are priced at or below 115 percent of the MPB, adjusting for RA and energy value; (ii) RPS contracts that if assigned, would result in a shortfall of RPS energy deliveries relative to the IOU's RPS compliance targets for any given year or would require the IOU to procure new long-term contracts in the next three years to meet its RPS compliance obligations; and (iii) contracts that are required to meet Commission mandates. The IOUs would request that Sellers indicate their interest by providing the IOU with their minimum requirements to consider a Contract Assignment with another LSE. The IOU will inform the market of Sellers' interest ("Interested Sellers") in Contract Assignments and will seek LSEs ("Prospective Buyers") interested in exploring the Contract Assignment and meeting Seller's expressed criteria for engagement (*e.g.* credit rating limitations, minimum term, etc.). The IOUs will match Interested Sellers with Prospective Buyers meeting the Interested Seller's minimum requirements and allow the Potential Buyers and Interested Sellers the opportunity to negotiate a Contract Assignment. Before the Interested Seller and Prospective Buyer begin negotiations for

Contract Assignments, each must execute an NDA with the IOU. Once NDAs are executed, and subject to Seller's consent, the IOU will provide Prospective Buyers with the Interested Seller's PPA and the last three (3) years of historical production of the project. Seller and Prospective Buyer may maintain the confidentiality of their negotiations and final terms and conditions, and neither the IOU nor the Commission may review the terms and conditions reached by Seller and Prospective Buyer, other than as required to comply with existing regulations. Following their negotiation, the Seller and Prospective Buyer may propose the terms of the negotiated Contract Assignment that would affect the IOU to the IOU for approval.

c) Contract Modification RFI

Coincident with the Contract Assignment RFI, the IOUs will request offers from their Sellers for potential Contract Modifications. Sellers may propose terminations, buy-outs, or amendments that result in net cost savings for customers. The IOUs will evaluate Sellers' proposals and will seek to negotiate agreements to amend or terminate the Seller's contract if desirable. The IOUs will file any successful agreements within their annual ERRA Review of Operations application or through an advice letter or other application, as appropriate and consistent with existing requirements, for Commission review and approval.

d) IOU Review and Approval

The Co-Chairs propose that with regards to Contract Assignments and Contract Modifications, the IOU has discretion, in its business judgment, to accept or reject any proposed transactions or arrangements, subject to Commission requirements. Further, SCE is concerned that it does not have the resources to effectively manage the hundreds of proposals that may be received. Therefore, the Co-Chairs propose that the IOUs be allowed to cap the number of active negotiations with counterparties each IOU will be required to enter into to 20 mutually exclusive offers from each RFI. SCE proposes that the IOU will need to evaluate offers received to determine which proposals to pursue. All transactions to which the IOU is a party will be subject to Commission approval, consistent with existing processes for contract review and approval. Any cost reductions arising from a Contract Assignment or Contract Modification will be reflected in PCIA rates for the vintage associated with the contract. Additionally, any payments made by the IOU in connection with a Contract Assignment or Contract Modification will be charged to the PABA sub-account corresponding to the resource's vintage.

SCE and Commercial propose that any contract termination payments be excluded from the \$0.005/kWh annual PCIA rate increase cap, established by D.18-10-019, as the PCIA cap was intended to manage volatility year-over-year rather than one-time transactions that may artificially trigger the cap because of large buy-out or termination payments that result in greater savings in subsequent years. SCE and Commercial do not believe the upfront cost of buying out these contracts was intended to be factored into the cap, as this will increase the PCIA cost to customers and potentially trigger the cap every year, which SCE and Commercial believe is not what the Commission intended. CalCCA, however, disagrees on grounds that an IOU's responsibility to optimize its portfolio through the RFI is no more onerous than the requirement to optimize their portfolios today under AB 57 and the Standards of Conduct. In other words, the Commission was fully aware of the potential for buy-outs or buy-downs when it adopted the cap in D.18-10-019, yet chose not to make such transactions an exception from the cap.

IOUs will be required to provide all LSEs notice of how portfolio optimization activities may affect their allocations in flow year.

e) Reporting on RFI

Each IOU will file a report summarizing the results of the Contract Assignment and Contract Modification RFIs. The report will identify (a) the full list of Sellers notified for potential inclusion in the Contract Assignment process, (b) the list of contracts assigned, terminated or otherwise amended, (c) the material terms of any proposed Contract Assignments or Contract Modifications, (d) the net impact on the IOUs' bundled and PCIA-eligible, vintaged positions, (e) a list of Contract Assignment proposals rejected by the IOU and the rationale for each rejection, (f) contracts currently in negotiations, and (f) the net customer value realized.

3. Rationale for Consensus Proposal

While contract assignments, terminations, buy-outs or amendments may currently occur organically with a generator contacting the IOU or vice-versa, the consensus proposal for the Contract Assignment and Contract Modifications RFI processes present a proactive approach to conduct a mass outreach to the IOUs' contracted generators and potentially spark creative thinking on the part of those Sellers to propose mutually beneficial transactions. This proposed mechanism provides an additional opportunity for removal of excess resources from the IOUs' portfolios by allowing other LSEs an opportunity to contract directly with generators currently bound by IOU contracts. This consensus proposal essentially provides two "open seasons" for contract restructuring, with greater visibility provided through reporting into the actions taken.

VII.

SCOPING ISSUE 3: TRANSITION TO NEW STANDARDS

Issue 3 asks "[i]f the Commission were to adopt standards for more active management of the utility portfolios, how should the transition to new standards occur (*e.g.,* timeframe, process, etc.)?" The proposals laid out by the Co-Chairs within Issue 1, while seeking to minimize impacts to existing processes, result in some proposed changes and additions to existing processes. The Co-Chairs suggest that the majority of the aspects identified in the WG 3 proposals can be ruled upon within a WG 3 Decision within R.17-06-026. However, there are a number of other proceedings or rulemaking venues that will also be affected and must affirmatively rule upon changes that are being proposed by the Co-Chairs to implement the proposed allocation proposals. Below, the Co-Chairs outline the proposed steps that must be taken to implement the Co-Chairs' proposed processes for each of the products.

A. Co-Chair Consensus Proposal on Full Implementation Process and Timelines

Starting in 2021, the Commission should order the IOUs to publish, within their annual ERRA Forecast of Operations applications, and subject to the confidentiality protections afforded by D.06-06-066, their vintage-specific, PCIA-eligible: (i) monthly Local, System, and Flexible RA positions, differentiating among the specific RA categories (*i.e.,* local area, flexible category, etc.); (ii) RPS energy positions, including information about long-term contracts and

PCC status; and (iii) GHG-free energy positions, by nuclear and non-nuclear pool, for the term of each PCIA vintage. This information will increase transparency to PCIA-eligible LSEs about the available positions to be allocated in the allocation and VAMO processes, facilitating early portfolio planning activities that will minimize market disruptions upon implementation of the WG 3 Final Decision. The first anticipated publication of this information may take place in the June 2021 ERRA Forecast of Operations application, pending the timing of the WG 3 Final Decision.

The Commission should rule that the IOUs update their BPPs to reflect the necessary changes for implementing the Local RA and GHG-free energy allocations, and the System and Flex RA VAMO processes, including, but not limited to, permitting allocations and re-allocations, revising volume limits and price floors for Market Offer sales or re-allocations, establishing Market Offer valuation, selection, and review processes, etc. It is expected that the IOUs may update their BPPs within 60 days of a WG 3 Final Decision, with Commission approval possible within 90 days thereof. This timeline would establish the updated BPP authority in approximately Q2 2021.

The Commission should also require the IOUs to update their RPS Procurement Plans to request approval to, among other things, conduct the RPS allocations and market offer, including establishing timelines, bidding requirements, valuation methods, etc.; conduct allocations and re-allocations; enter into long-term (*i.e.,* 10 years or more) allocations and sales; use new contracts for the Market Offer sales; revise limits on volumes that may be allocated or sold; revise price floors; etc. It is anticipated that these changes could be ruled upon within the 2021 RPS Procurement Plan filings for RPS energy deliveries in 2022.

The Co-Chairs recommend that the Commission rule by June 2021 that Track 4 of the RA OIR, slated for December 2020, be scoped to explore (i) the modifications needed to the RA process and timelines to accommodate the completion of the System and Flex RA VAMO process and to provide sufficient time following the RPS energy and fall System RA and Flex RA Market Offer processes to implement the Market Offer results into the annual Update to

ERRA Forecast application in November; (ii) establishment of the PCIA Showing mechanism, which is needed for Local and System and Flex RA allocations; and (iii) methodologies for LSEs to submit and the CPUC and/or CEC to calibrate vintaged annual- (MWh) and peak- (MW) load forecasting, which is needed for each of the four product allocations proposed by the Co-Chairs. The Co-Chairs recommend that these topics be ruled upon by June 2021, and be implemented for the 2022 compliance filing year, which would allow for deliveries in 2023.

Additionally, PCIA-eligible LSEs may wish to have additional clarification provided by the CEC on how it will treat allocated RPS and GHG-free energy on the PCL. The Co-Chairs request that the Commission consult with the CEC to ensure guidance is provided on how allocations may be structured to meet requirements of Assembly Bill ("AB") 1110.

The Commission should require the IRP OIR to address (i) how to implement allocations of Local and System and Flex RA, RPS energy, and GHG-free energy into the development of the RSP; (ii) how vintaged peak- and annual-load share forecasting should work in this context; and (iii) how allocations will affect LSEs' procurement targets for the IRP cycle that will begin in 2022. The allocations can be implemented, however, in advance of determining the accounting for IRP purposes.

1. Local RA Allocation and System and Flex RA Voluntary Allocation and Market Offer Implementation Timelines

It is anticipated that the regulatory decisions required for implementing Local and System and Flex RA allocations and market offer processes, as applicable, may be decided by mid-2021. The Commission would determine in the RA OIR the necessary changes for the Local and System and Flex RA allocation proposals to be incorporated into the 2022 RA filing process for the 2023 compliance year. Thus, the Co-Chairs suggest that the VAMO for System and Flex RA may commence in 2022 for the 2023 compliance year. By the time the WG 3 Final Decision is expected to be issued, in Q4 2020, most LSEs will have met 100 percent of their Local RA compliance obligation for 2022 and 50 percent of their obligation for 2023. The Co-Chairs propose that Local RA allocation also be implemented in the 2022 filing year, but only for the 2024 and 2025 compliance years.

2. GHG-Free Energy Voluntary Allocation Implementation Timeline

The proposed voluntary allocation process for GHG-free energy relies upon the IOUs' BPPs being updated and having calibrated, forecasted, vintaged, annual-load shares for each LSE. The BPPs are anticipated to be approved by the Commission by approximately Q2 2021. The methodology for submitting and calibrating load shares is proposed to be decided within the RA OIR. This decision is not anticipated until mid-2021, and thus the forecasting requirements would be ready for implementation in 2022 for 2023. The Co-Chairs recommend that the proposed GHG-free voluntary allocation be implemented in 2022 for 2023.

Despite the fact that the RA OIR has to rule upon the proper methodology for submittal and calibration of LSEs' vintaged, annual load forecasts, the Co-Chairs believe that the GHG-free energy allocation is the simplest product to allocate. With some minor modifications, such as utilization of LSEs' actual, vintaged loads for the first year, rather than forecasted, vintaged loads, implementation of the GHG-free energy allocation could take place sooner than 2023. As an interim solution, the Co-Chairs propose that the IOUs could provide voluntary allocations to PCIA-eligible LSEs on the basis of either a forecasted load share or their actual annual load shares, as determined by the individual IOU. Pacific Gas and Electric Company ("PG&E") has already submitted a proposal for the sale or allocation of GHG-free energy to enable an interim process in advance of a WG 3 Final Decision.[38] SCE plans to offer a similar interim GHG-free energy allocation, which will be submitted for Commission review through an advice letter, and would enable voluntary allocations to PCIA-eligible LSEs on the basis of their actual annual load shares, starting within 30 days of Commission approval.

---

[38] PG&E Advice Letter 5705-E.

3. RPS Energy VAMO Implementation Timeline

The RPS VAMO process will depend on the Commission ruling upon the IOUs' RPS Procurement Plan updates to incorporate the RPS VAMO process. The Co-Chairs propose that the IOUs file their proposed changes in the next RPS Procurement Plans following the WG 3 Final Decision, which would be expected to be ruled upon in late-2021 for RPS energy deliveries in 2022. The RPS VAMO process will also rely on the RA OIR to rule upon the appropriate methodology for LSEs to submit and the CPUC and/or CEC to calibrate LSEs' vintaged, annual load forecasts. This process is anticipated to be ruled upon in 2021 for implementation in the 2022 RA filing year for the 2023 compliance year. Thus, the Co-Chairs anticipate that the RPS VAMO process may not be fully implemented until 2022 for deliveries in 2023.

4. Proposed Ratemaking Implementation Timeline

The Co-Chairs propose that the WG 3 Decision is the appropriate venue to update the Ratemaking requirements from D.19-10-001 to accommodate the Co-Chairs' proposal on appropriate ratemaking treatment within the PCIA. The change in ratemaking for each product should be effective coincident with the year in which such product would first be subject to the allocation or VAMO treatment contemplated by WG 3. The Co-Chairs contemplate that in the case of the VAMO, the results of the Market Offer process will be available prior to setting PCIA rates in the IOUs' November Update to ERRA Forecast applications, and thus should be incorporated into the updated MPB for the applicable product type.

B. Interim Implementation Proposals

1. Non-Consensus Interim RA Implementation Proposal

CalCCA and Commercial Energy propose that Local and System and Flex RA could be allocated beginning in 2021 for the 2022 System and Flex RA compliance year and the 2023 and 2024 Local RA compliance years pursuant to the following steps:

- Non-IOU, PCIA-eligible LSEs will meet and confer with the IOUs following the existing process prior to the initial year-ahead load forecast deadline in April 2021.

- CCAs and LSEs will provide IOUs with vintaged, monthly peak load forecasts for each of their vintages, totaling to their overall peak load.
- Parties will seek to agree on vintage peak load forecasts. If differences cannot be resolved between an IOU and an LSE, differences will be resolved through the CPUC mediation process.
- Allocations will be made based on the vintaged load forecasts, and will include 2022 System and Flex RA and 2023/2024 Local RA.
- By the end of July 2021 the CPUC will publish the preliminary RA obligations. The IOUs will apply the vintaged load shares to the PCIA-eligible RA positions to estimate the eligible vintage allocations for each LSE.
- Within 5 business days of receiving the initial RA obligations, the IOUs will notify each LSE of their eligible RA allocation volumes.
- LSEs will have 5 business days to submit their System and Flex RA allocation elections.
- Local RA allocations will be mandatory and the Co-Chairs' proposed ratemaking treatment will be recovered in 2023 and 2024 calendar years from customer PCIA rates.
- The RA allocation will be performed through the PCIA Showing.
- Trading will only be permissible if a suitable mechanism is worked out.
- LSEs receiving the System and Flex RA allocations will pay the IOU at the relevant MPB. Revenues will be treated like sales for purposed of PABA accounting.

SCE opposes an early or interim implementation for Local and System and Flex RA allocations. The IOUs need sufficient time to realign their portfolios to account for considerable increase in showing obligations, particularly if secondary trading of the PCIA Showing is unavailable.

2. Non-Consensus Interim RPS Energy Implementation Proposals

The Co-Chairs propose that an interim RPS voluntary allocation approach be pursued on the basis of LSEs' actual, vintaged, annual load shares and without a Market Offer process. Allocations would be treated as sales in the PCIA methodology at the RPS MPB. Declined allocations would remain with the IOU. Any RPS energy held by the IOU would continue to be treated in accordance with D.19-10-001. The Co-Chairs request the Commission specify that during this transition period excess RPS generation, excluding banked RECs, may be valued at $0/MWh for purposes of the PCIA only to the extent that it (i) is offered for sale by the IOU, (ii) remains unsold, and (iii) is in excess of the IOU's interpolated annual RPS compliance target.

CalCCA and Commercial propose that changes needed to the IOUs' RPS Procurement Plans could be accomplished via a Motion to Update, which could be requested as soon as practical following the WG 3 Final Decision with allocations to commence no less than 30 days following approval, thus permitting allocations to begin in 2021.

SCE proposes that interim RPS energy voluntary allocations could commence deliveries as early as 2022, provided appropriate timelines are allowed for updates to RPS Procurement Plans, receipt of necessary regulatory decisions, and for the market to prepare for the new requirements. To the extent that implementation of such interim RPS energy allocations would jeopardize the IOUs' abilities to meet their RPS compliance requirements, cause undue cost increases, or cause cost shifts to bundled service customers, the IOUs may petition the Commission to delay implementation. In addition, the IOUs will need to consider how to manage or sell their excess RPS energy positions for 2021 prior to receiving a WG 3 Final Decision, creating potential conflicts with requirements to conduct earlier allocations.

VIII.
SCOPING ISSUE 4: SHAREHOLDER RESPONSIBILITY

This section addresses the question of whether the Commission should consider new or modified shareholder responsibility for future portfolio mismanagement, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards, and whether the ERRA or General Rate Case ("GRC") proceedings are the appropriate forums to address prudent management of portfolios.

A. <u>Co-Chair Consensus Proposal</u>

The Co-Chairs do not propose new or modified IOU shareholder responsibility for alleged portfolio mismanagement. However, the Co-Chairs agree that each IOU should file a report on its implementation of the newly proposed RFI process (see Section VI.B.2.e above) and outcomes thereof, including identification of rejected offers and the bases for rejection. Additionally, the Co-Chairs agree that the IOUs shall report in the annual ERRA Review of Operations application (1) material events of defaults and any termination rights and any actions taken with respect thereto in a single section consistently formatted in each IOU's filings; and (2) cost savings received from active portfolio management.

B. <u>Rationale for Consensus Proposal</u>

The Co-Chairs agree that the information proposed for inclusion in the RFI report, as noted above, is reasonable. Moreover, any resulting assignment, modification or termination of a contract pursuant to the RFI process would be subject to Commission review and approval in the ERRA Review of Operations or other application or advice letter for cost recovery purposes consistent with existing requirements.

C. <u>Non-Consensus Proposal</u>

The Co-Chairs were unable to reach consensus on the timing, frequency, and venue for filing the IOU's report on the RFI process, and the extent to which the IOUs are subject to disallowances based on actions not taken in response to the RFI, as submitted in the report on the RFI process. SCE and CalCCA plan to submit individual opening and reply comments advancing their respective positions on this Non-Consensus Item.

IX.

<u>CONCLUSION</u>

The Co-Chairs appreciate the opportunity to submit this Final Report, and respectfully request that the Commission promptly issue a Final Decision adopting the Co-Chair Consensus

Proposals discussed herein, as summarized in the Executive Summary (Section II above) and discussed in detail in this Final Report. The Co-Chairs further request that the Commission resolve the Non-Consensus Items discussed herein in its Final Decision on the WG 3 issues.

Respectfully submitted,

JANET S. COMBS
RUSSELL A. ARCHER

/s/ Janet S. Combs
By: JANET S. COMBS

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPAN

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1524
Facsimile: (626) 302-3990
E-mail: Janet.Combs@sce.com

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY, CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY

February 21, 2020

Appendix A

THIRD WORKSHOP PRESENTATION

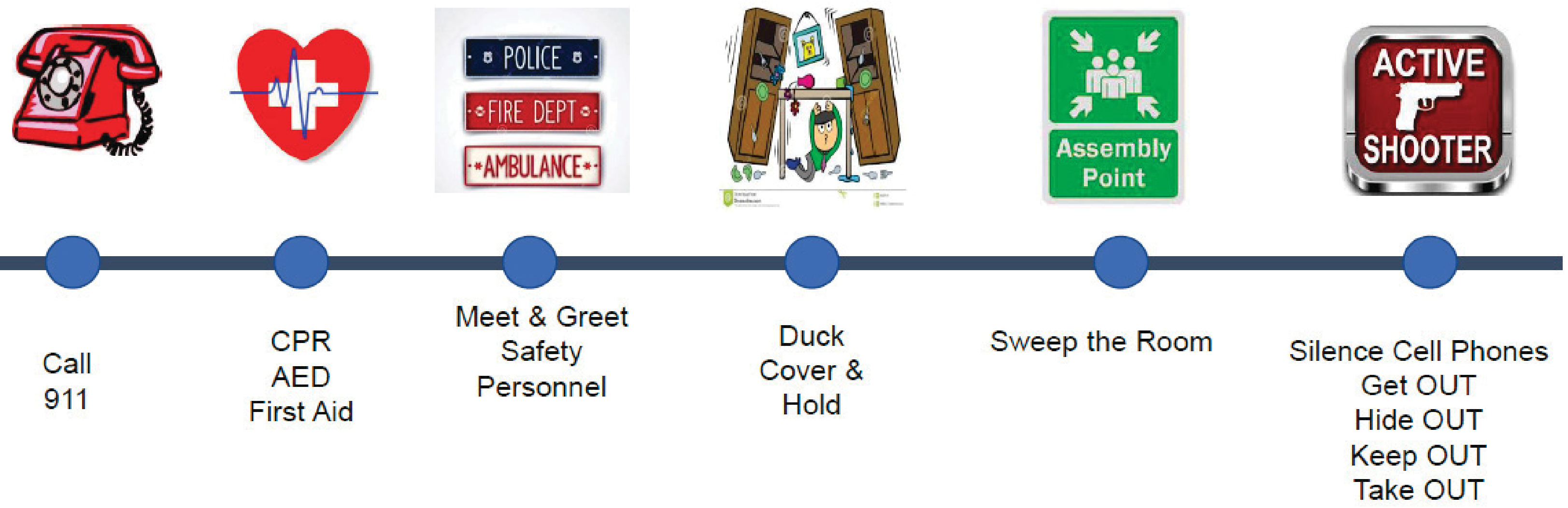
PCIA Phase 2 – Working Group Three

Portfolio Optimization and Cost Reduction, and Allocation and Auction

Voluntary Allocation & Market Offer Process for RPS and System/Flex RA

Workshop No. 3
October 17, 2019

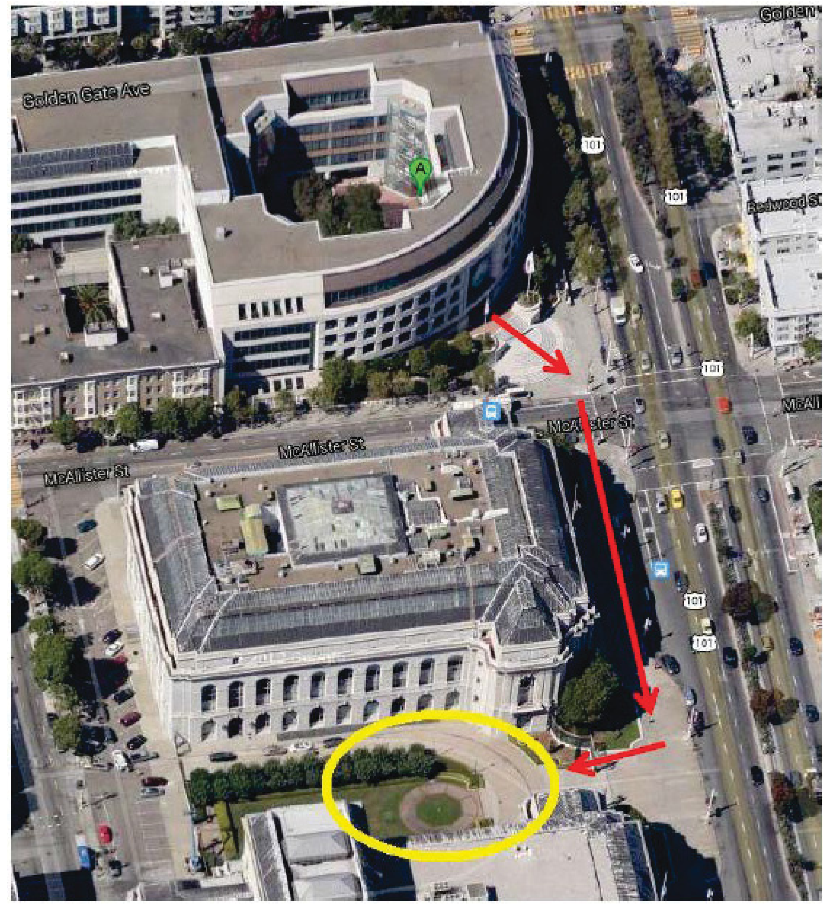
Safety – Roles & Responsibilities



Safety – Evacuation Procedure

In the event of an emergency evacuation:

- Cross McAllister Street
- Gather in the Opera House courtyard down Van Ness, across from City Hall.



WiFi Access

Network: CPUCguest

Username: guest

Password: cpuc93019

Agenda

- Safety and Status Check
- Recap and Update of Positions from Second Workshop
- Overview of Voluntary Allocation & Market Offer Proposal
- RPS Proposal
  - Voluntary Allocation Mechanism
  - Voluntary Market Offer Mechanism
  - Long-Term RPS Sales
- System/Flex RA-Specific Mechanisms
  - Voluntary Allocation Mechanism
  - Voluntary Market Offer Mechanism
- Ratemaking Options
- Next Steps

Working Group Three – Issues to be Discussed
Scoping Memo R.17-06-26

1. What are the *structures, processes, and rules governing portfolio optimization* that the Commission should consider to address excess resources in utility portfolios? How should these processes/rules be structured to be compatible with the IRP and RA program modifications proceedings?

2. What standards should the Commission adopt for *more active management of the utilities' portfolios in response to departing load* in the future to minimize further accumulation of uneconomic costs?

3. If the Commission were to *adopt standards for more active management of the utility portfolios*, how should the transition to new standards occur (e.g., timeframe, process, etc.)?

4. Should the Commission *consider new or modified shareholder responsibility or future portfolio mismanagement*, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards? Are ERRA or GRC proceedings the appropriate forums to address prudent management of portfolios?

Recap from Prior Workshops

Summary of Prior Workshops

- Excess Sales Framework for RA and RPS
  - Presented framework in prior workshops but did not reach consensus upon certain items including:
    - Buffer
    - Uncertainty Tranche
    - Timing of Solicitations
    - Capacity with Operational Issues
- Local RA Allocation Proposal
  - Mandatory allocation via a CAM-like mechanism, but may be traded*,**
    - Commercial supports voluntary allocation with auction of unallocated RA
  - Multi-year forward allocations track Local RA obligations
  - System and Flex RA from Local resources follows Local RA allocation
  - Allocated products receive a benchmark value of $0 in PCIA mechanism
- Voluntary GHG-Free Energy Allocation Proposal
  - Voluntary option to accept all or none of Nuclear or Non-Nuclear pools of GHG-free energy
    - Unallocated energy is re-allocated amongst LSEs accepting allocation
    - Commercial Energy supports voluntary allocation of any portion of pools, with unallocated energy being auctioned off
  - IOU continues to serve as Scheduling Coordinator for energy
  - No change to PCIA rates, as GHG-free energy receives no additional benchmark value

* SCE is neutral to trading of Local RA after an allocation, but if permitted, does not believe IOUs should be required to manage the process

** CalCCA will not support any allocation scheme that does not allow trading of allocated products

Updates to Proposals from Second Workshop

- Local RA
  - Recommend allocating on a forecasted, vintaged peak-load share basis, as determined by CPUC/CEC
    - Approach would follow existing processes, but would require submittal of vintage load forecasts and calculation of vintage peak loads*
  - Allocations will be provided pro-rata across all Local RA areas
- GHG-Free Energy
  - Recommend allocating on an annual, vintaged load-share basis based upon actual annual load and production

* Will impact CPUC, CEC, and LSEs in determining vintaged peak-load shares and tracking allocations

Voluntary Allocation and Market Offer Proposal for RPS and System/Flex RA

PCIA Phase 2 - Working Group 3

Definitions (applicable to all proposals)

- LSE – PCIA-eligible Load Serving Entities
- Allocation – the transfer of attributes and/or energy to LSEs based upon their customers' payment of PCIA rates and in proportion to their customers' vintaged annual- or peak-load shares, as applicable
- Market Offer – an annual offering, facilitated by IOUs, of unallocated products to the market in which products are sold to the highest bidders subject to a floor of $0
- GHG-Free Energy – Energy delivered from non-RPS, GHG-free resources, along with the right to claim such energy on an LSE's Power Content Label
- RPS Energy – Energy delivered from RPS resources, along with the RECs and right to claim such energy on an LSE's Power Content Label
- CAM-like mechanism – a process for allocating capacity wherein the IOU shows capacity on its supply plan, and that capacity is allocated as credits and debits to LSEs that are tracked by the CPUC in a fashion that is similar to the existing CAM allocation process

Concept for Voluntary Allocation & Market Offer Proposal for RPS and System/Flex RA

- LSEs can make an annual election to accept or decline an allocation of their vintaged share of available PCIA-eligible RPS energy & System/Flex RA
- IOU will offer to the market the unallocated RPS energy and/or System/Flex RA
- IOU will continue to manage the PCIA portfolio, performing the following functions:
    - Schedule energy into the CAISO market;
    - Show RA through a CAM-like mechanism;
    - Transfer bundled RECs to benefiting LSEs; and
    - Provide information to certify RPS energy for Power Content Label
- IOU may continue to perform portfolio optimization activities outside of Voluntary Allocation and Market Offer mechanism
    - Additional details to be discussed at the next WG 3 Workshop

Comparison of Voluntary Allocation & Market Offer vs Other Concepts

Mechanism	GAM/PMM	Excess Sales	Local RA Allocation	GHG-Free Allocation	RPS Energy Allocation & Market Offer	System / Flex RA Allocation & Market Offer
Products	RPS Energy; GHG-Free Energy; System, Flex, Local RA from RPS Resources	RPS Energy; System, Flex, Local RA	Local RA	GHG-Free Energy	RPS Energy	System and Flex RA
LSE Choice	Mandatory	N/A	Mandatory	Voluntary	Voluntary	Voluntary
IOU Retained Volume	Pro-Rata Share	Bundled Need	Peak-Load Share*	Annual Load Share*	Annual Load Share*	Peak-Load Share*
Sales from Portfolio	Gas-fired RA Energy**	RPS Energy System, Flex, and Local RA Energy**	Energy**	Energy**	Unallocated RPS Energy Energy**	Unallocated System / Flex RA Energy**
PCIA Revenue Offsets	Energy Revenue RA Sales	Energy RPS Energy System, Flex, Local RA	N/A	N/A	Unallocated RPS Sales Revenue	Unallocated System / Flex RA Sales Revenue

* Vintaged basis
** Energy is scheduled by IOU into CAISO market

Voluntary Allocation and Market Offer Mechanism for RPS

PCIA Phase 2 - Working Group 3

RPS Voluntary Allocation Structure

- RPS allocation share is based on actual, annual, vintaged load share and actual production over the course of the flow year*
  - Actual allocation amount and energy profile is subject to availability after accounting for any existing sales or other portfolio management activities by IOU
- Allocation conveys bundled RPS energy and RECs, Power Content Label credit, and Integrated Resource Plan credit
  - Allocations preserve underlying contracts' PCC status
- LSEs may elect to decline their allocation during an "open enrollment" period in 10% increments
  - IOUs will offer unallocated RPS amounts for sale to the market annually
- LSEs may sell allocated RPS energy outside of the IOU voluntary market offer process
- Allocations should be structured to preserve long-term attributes
  - SCE & Commercial: Long-term attribute should be preserved regardless of term of allocation
  - CalCCA: LSEs must accept 10+ year RPS allocations to preserve long-term attributes

* See Appendix (pg. 36-37) for illustrative, numerical example demonstrating how allocations work on a vintaged basis

RPS Voluntary Market Offer Structure

- Annually, the IOU will offer to sell all unallocated RPS energy for a term beginning in the prompt year
  - Long-term sales (i.e. for 10+ years) will be offered*,** up to a percentage cap applied to the lesser of LSE's (a) total allocation share or (b) sales election
    - RPS sales will convey long-term attributes only if sold for 10+ year terms
  - Remaining unallocated RPS energy will be sold only for prompt year
  - Sales will be structured to preserve underlying PCC status
- Voluntary market offer will be conducted once annually as follows:
  - Using pre-approved mechanisms for RFO administration, valuation, selection, and contracting;
  - Monitored by an Independent Evaluator; and
  - CAM group shall be consulted on offer selections
- Offering will be open to all market participants, including IOUs

* IOUs and Commercial Energy concerned about long-term sales. SCE and Commercial Energy would not support a cap above 25%.
** CalCCA is concerned about restrictions to long-term sales and would not support a 25% percent cap. CalCCA discussing appropriate threshold for long-term sales.

Timeline for RPS Voluntary Allocation & Market Offer

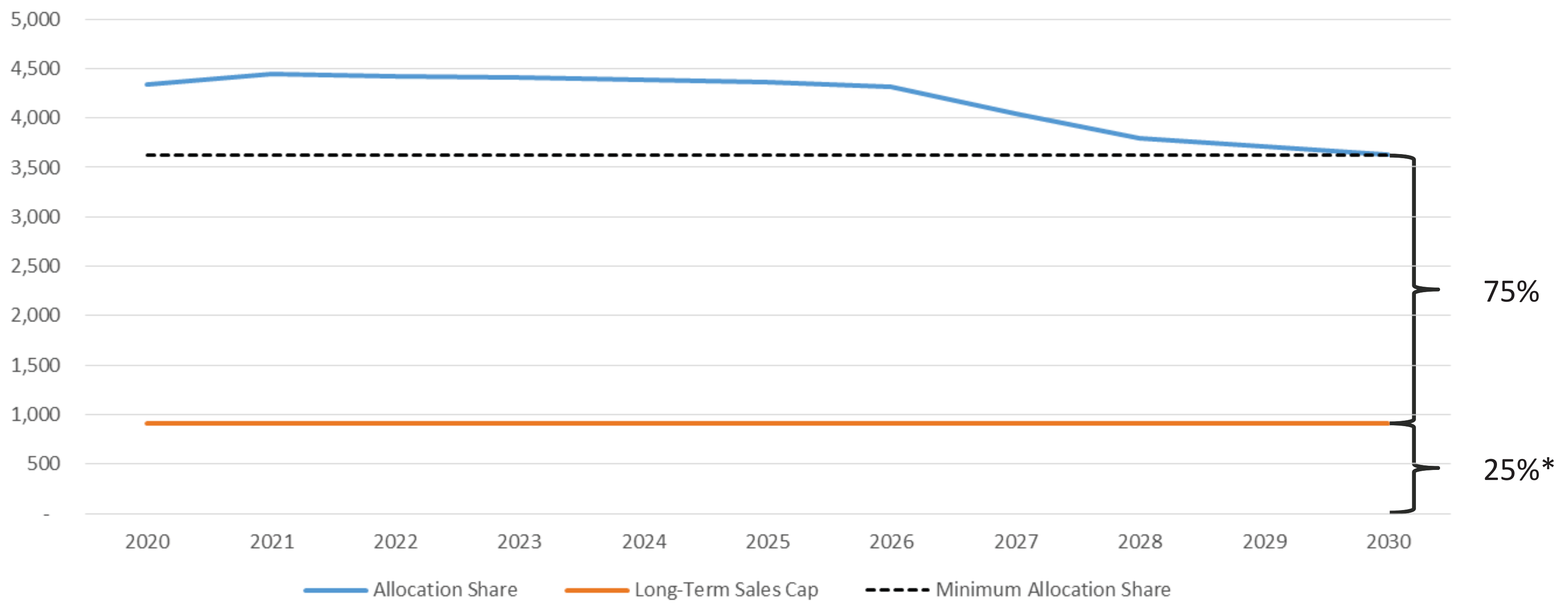
RPS Allocation & Market Offer Indicative Timeline	**Proposed Date**	**Year**
Publish RPS Generation Forecast in ERRA Forecast	Current IOU ERRA Forecast Date	N-1
LSE receives CPUC forecasted vintaged load share	Early August	
Open enrollment for LSE's allocation	Mid August	
Market Offer of unallocated RPS	August-September	
Monthly aggregated meter data published	Jan-Dec	N
Perform REC transfers for Sales	30 days following creation in WREGIS	
Determine actual LSE load shares	Q1	N+1
True up RPS generation	Q1	
Perform REC transfers for Allocations	By end of Q2	
Retire RECs for compliance	July	

RPS Sales Contract Structures

- Potential Contract Types
  - Firm – Firm quantity, no profile
  - Slice of generation – Non-firm quantity, RPS portfolio shape
  - Contingent – Balance of un-allocated RPS energy, non-firm quantity, non-firm profile
    - Mix of products need to be structured to deal with portfolio variability
- Term: One year or 10+ years, starting in prompt year
- Pricing structured as Index + REC premium
  - No price escalators over multiple years
- Buyers need to be appropriately collateralized to protect all LSEs

Long-Term RPS Sales Illustration

- IOU will sell un-allocated RPS energy long-term (10+ years) up to a capped percentage of the lesser of LSE's (a) allocation share or (b) sales election, as a long-term sale of 10+ years
- Long-term sales amounts will be based upon the LSE's forecasted minimum allocation for the term of the long-term offer



* 25% is being used here for illustrative purposes

Long-Term RPS Sales Proposal

- IOU will only enter into long-term sales if they are the most valuable offer in the offer stack
  - e.g., if IOU receives offers with prices as indicated below, then IOU selects in the following order until all capacity has cleared: D, A, C, B
    - A. 1 year at $10/MWh
    - B. 1 year at $8/MWh
    - C. 12 years at $9/MWh
    - D. 10 years $12/MWh
- If LSE's load share drops such that the capped percentage for long-term sales threshold is exceeded, no long-term sales will be performed
- Proceeds from long-term sales are co-mingled with short-term sales
  - Simplifies ratemaking by allowing all customers to pay same PCIA rates

System/Flex RA-Specific Mechanisms

PCIA Phase 2 - Working Group 3

System/Flex RA Voluntary Allocation Structure

- IOU will annually offer all LSEs an allocation of their vintaged share of PCIA-eligible System and Flex RA
  - RA allocation share is based on forecasted, monthly, vintaged peak-load share as determined by the CPUC*,**,***
    - Actual allocation amount is subject to availability after accounting for any existing sales or other portfolio management activities by IOU
    - System and Flex RA attributes tied to Local RA resources will follow the mandatory Local RA allocation mechanism
  - LSEs may elect to decline their allocation during an "open enrollment" period in 10% increments, rounded to nearest MW
    - Unallocated RA will be offered for sale to the market by the IOU annually
- Allocations conveyed through a CAM-like mechanism
  - Allocation is credited to LSEs and debited from IOUs by CPUC***
- LSEs may sell allocated System and Flex RA outside of the IOU voluntary market offer process

* See Appendix (pg. 45-46) for illustrative, numerical example demonstrating how allocations work on a vintaged basis
** See Appendix (pg. 44) for explanation of how the CAM-like mechanism would compare to CAM
*** Will impact CPUC, CEC, and LSEs in determining vintaged peak-load shares and tracking allocations

System/Flex RA Voluntary Market Offer Structure

- The IOU will offer to sell all unallocated System and Flex RA for the prompt year
- Voluntary market offer will be conducted once annually as follows:
  - Using pre-approved mechanisms for RFO administration, valuation, selection, and contracting;
  - Monitored by an Independent Evaluator; and
  - CAM group will be consulted on offer selections
- Offering will be open to all market participants, including IOUs

Indicative Timeline for System/Flex RA Voluntary Allocation & Market Offer

- Co-Leads still discussing timelines. A final proposal has not been agreed to.
- Existing RA timelines impose tight constraints for completing the RA Voluntary Allocation & Market Offer process

System/Flex RA Allocation & Market Offer Indicative Timeline	Status Quo Milestones	Existing Dates	Year
CPUC identifies preliminary LSE allocation shares	Coincident with preliminary RA obligations' publication	~8/10	N-1
Open enrollment for LSE's allocation	Mid August*	N/A	
CPUC identifies final LSE allocation shares	Coincident with final RA obligations' publication	~9/20	
CPUC publishes final NQC	Existing NQC publication date	~9/20	
Market Offer of unallocated RA	Mid September to early October*	N/A	
Year Ahead RA Showing	October 31	10/31	
Month Ahead RA Showings	T-45	T-45	N

- Co-Leads recommend moving RA timelines earlier in the year, which would provide more flexibility for LSEs to conduct their RA procurement

* Indicative dates are based upon today's RA and Direct Access service request timelines

System/Flex RA Contract Structures

- Contract structured as a confirm under the EEI Master Agreement
- Term: One month to one year for prompt year
- Pricing: $/kW-month
- Buyers need to be appropriately collateralized to protect all LSEs

System/Flex RA Transfer Mechanisms

- IOU will show PCIA-eligible RA capacity on annual and monthly RA supply plans
  - IOU responsible for substitution and other obligations of showing capacity
    - Any substitution capacity, CPM charges, and any CAISO costs or penalties required for, or imposed as a result of, System/Flex RA resource outages will receive full cost-recovery through the appropriate PABA account
      - **Exception:** Any costs disallowed through the IOU's ERRA proceeding would not be passed through PABA
- CPUC will notify LSEs of the debits or credits to their supply plans resulting from the CAM-like mechanism*
- LSE must show its PCIA credit on its showing to receive credit for allocation
  - LSE must show its PCIA debits corresponding to any sales of PCIA allocation

* Will impact CPUC in tracking allocations

Voluntary Allocation & Market Offer Ratemaking Mechanisms

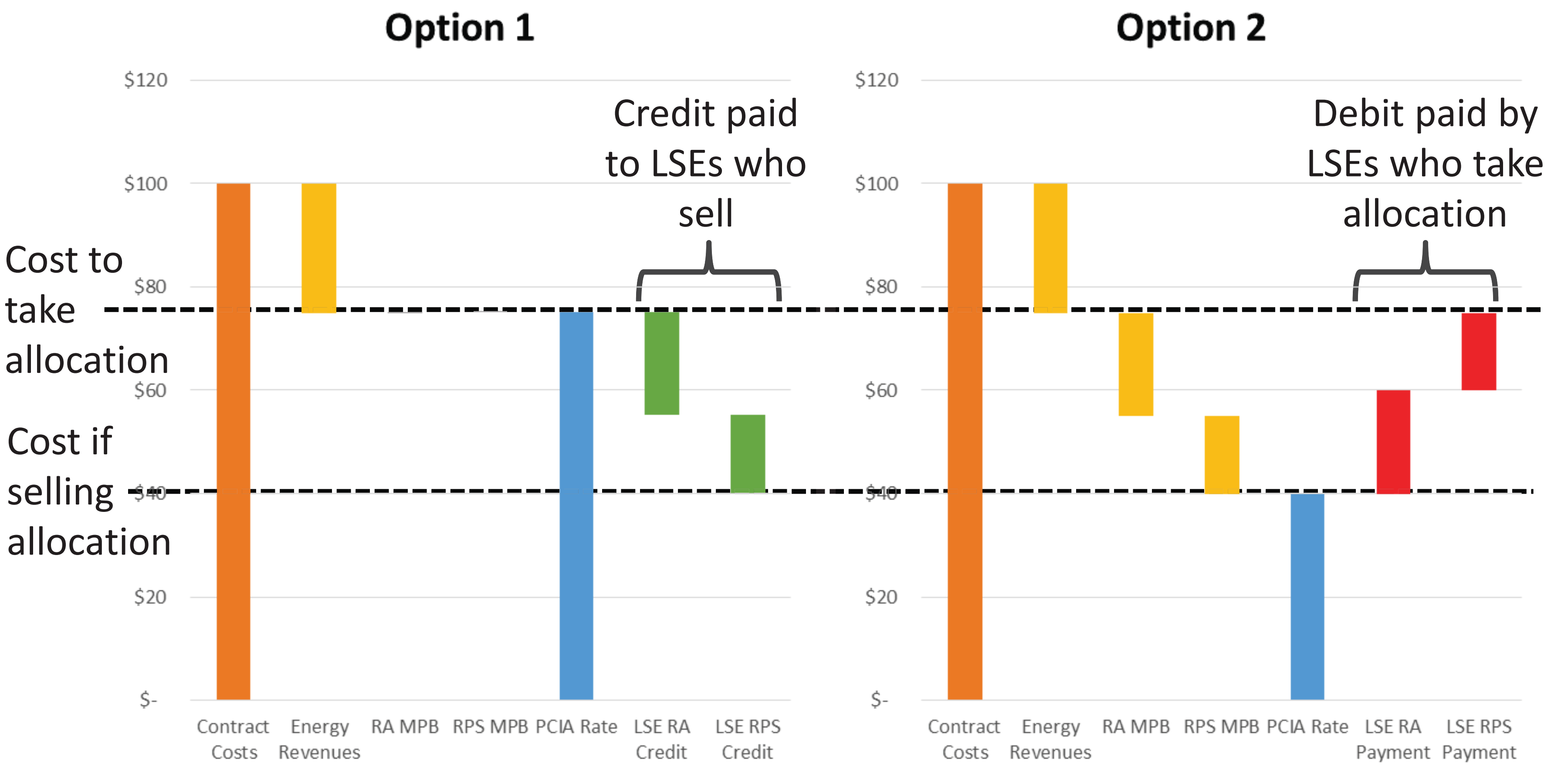
PCIA Phase 2 - Working Group 3

PCIA Ratemaking Structure

- Seek to minimize complexity of PCIA ratemaking and billing
- All customers in the same vintage pay the same PCIA rate
- Option 1: (Preferred by SCE and Commercial)
  - All customers pay full resource costs, less CAISO revenues
  - Product types available for allocation receive $0 value
  - LSEs wishing to sell products receive a direct payment from the IOU according to the LSEs' proportional share of the realized sales revenues*
- Option 2: (Preferred by CalCCA)
  - All customers pay full resource costs, less CAISO revenues, less the quantity of products in portfolio multiplied by PCIA product market price benchmark ("MPB")
  - LSEs wishing to take allocations must pay the PCIA product MPB for all products accepted as an allocation
    - An alternative to the PCIA product MPBs would be an "*auction price benchmark*" or "APB". Use of an APB makes LSEs indifferent to taking allocation or monetizing allocation through sales

* See Appendix (pg. 38-40) for illustrative example of how revenues would be re-allocated amongst LSEs choosing to sell products

PCIA Ratemaking Proposal Comparison



Assumes LSEs take allocation
Credits LSEs who sell allocation

Assumes LSEs sell allocation
Charges LSEs who take allocation

Comparison of Ratemaking Options

	Option 1	Option 2
Payment Structure	All through PCIA but eliminates MPB credit for product value	Combination of existing PCIA method with offsetting product value paid by LSE, credited to PABA
Rate Consistency	Under both options, no LSE-specific rates, reducing billing and ratemaking complexity	
Customer Rate Indifference	Under both options, customers would be indifferent whether LSEs take allocations or offer products for sale	
Exposure to Buyer Default Risks	No exposure by Allocatees	All LSEs exposed to Buyer default risks
Re-allocation of Un-Sold Products	Free re-allocation to LSEs choosing to sell*	Free re-allocation to LSEs choosing to sell. Solicitation results and un-sold products valued at $0 are incorporated into MPB
Allocatee Collateral	None	Appropriate credit backstop
Impact on PCIA rate	Higher than today, but offset by receipt of products and/or revenues	Not significantly different from today

* All RPS and RA transferred to LSEs through initial allocation or re-allocation of unsold are valued at $0

Next Steps

Feedback Requested

- Co-Leads are seeking feedback on concepts presented by 10/28
  - Please submit informal comments through CPUC Service List

- Topics the Co-Leads would ask the audience to opine upon in informal comments:
  - Voluntary Allocation & Market Offer Structure Proposal
  - RPS Process
    - RPS Long Term Sales Proposal
  - RA Process
    - Timelines
    - System/Flex RA CAM-Like Mechanism
  - Ratemaking Proposals

Next Steps

- Review informal comments received from workshop participants and refine Voluntary Allocation and Market Offer proposal
- Commence discussions on Issues 2-4:
  2. Standards for management of IOU portfolios
  3. Transition to Voluntary Allocation & Market Offer approaches
  4. Responsibility for portfolio mismanagement
- To inform positions on Issues 2-4, Co-Chairs ask that Parties submit any proposals through informal comments to the CPUC Service List by 11/4
- Upcoming deliverables:
  - Fourth WG3 Workshop expected early- to mid-December, 2019
    - Refinement of Voluntary Allocation and Market Offer process
    - Issues 2-4
  - Final Report due January 30, 2020

Appendix

SCE Proposed Process for Regulatory Approval of Voluntary Market Offer Contracts

- IOU updates Bundled Procurement Plan and RPS Procurement Plan to reflect that it will be conducting annual auctions on behalf of LSEs
  - Permits authority for IOU to enter into long-term sales of PCIA-eligible RPS
- IOU files an Advice Letter requesting pre-approval of:
  - RPS confirms to be used in the auctions
  - Proposed auction process, valuation methods, and offer selection mechanisms
- IOU adheres to established processes as follows:
  - Consults with CAM group prior to (i) auction launch and (ii) final offer selection and contract execution
  - Files executed contracts in appropriate filing:
    - Annual ERRA testimony; *or*
    - Quarterly Compliance Report; *or*
    - A single Advice Letter documenting the auction results
  - Review of IOU actions constrained to whether IOU followed process appropriately. Contract prices are not subject to review, as the auction seeks to clear all products at any price greater than $0.

RPS-Specific Mechanisms

RPS Voluntary Allocation Example

1. Determine LSE annual loads, peak loads, and vintages

LSE Assumptions (Illustrative)	Annual Load (GWh)	Peak Load (MW)	Vintage
SCE	55,000	13,000	N/A
Direct Access	12,500	2,200	2009
CCA1	1,000	360	2015
CCA2	500	225	2017
CCA3	12,000	3,000	2018
CCA4	400	140	2018
CCA5	1,600	450	2020

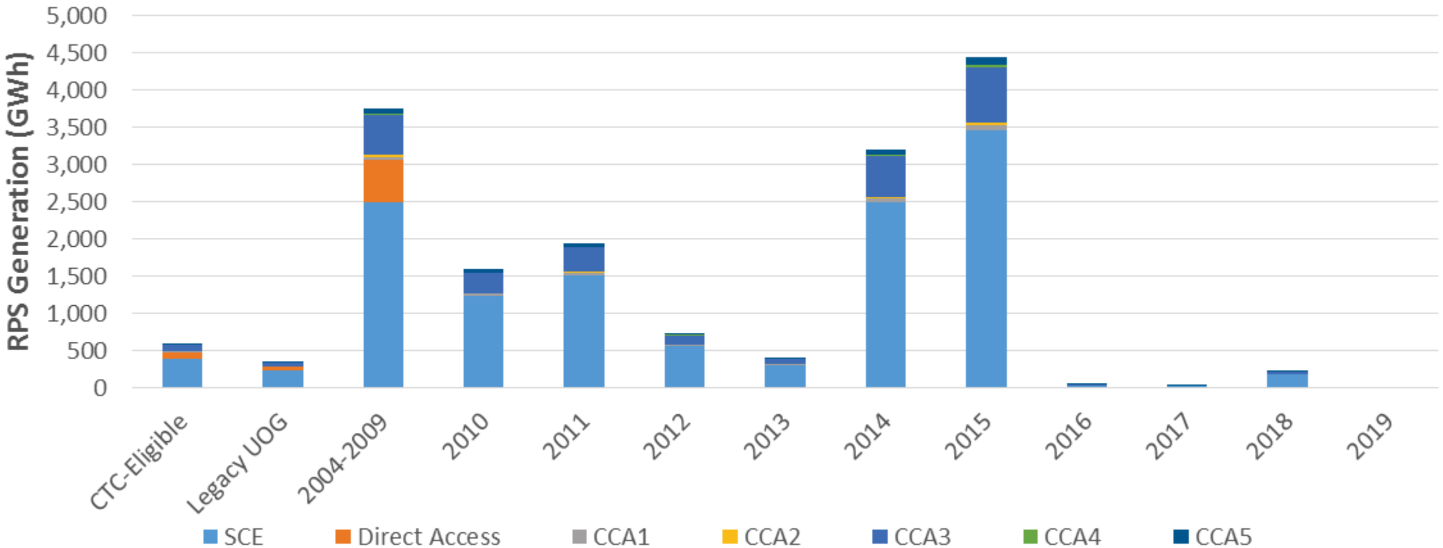
2. Determine vintaged LSE load shares

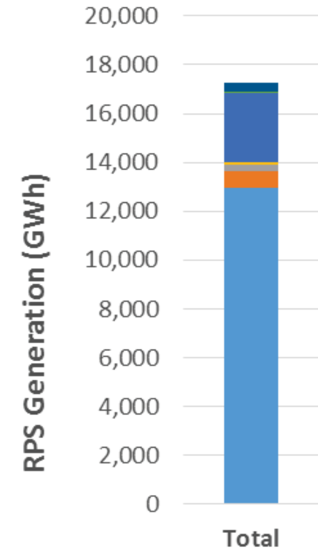
LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SCE	N/A	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000	55,000
Direct Access	2009	12,500	12,500	12,500										
CCA1	2015	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000				
CCA2	2017	500	500	500	500	500	500	500	500	500	500	500		
CCA3	2018	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	
CCA4	2018	400	400	400	400	400	400	400	400	400	400	400	400	
CCA5	2020	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Total Load (GWh)		83,000	83,000	83,000	70,500	70,500	70,500	70,500	70,500	70,500	69,500	69,500	69,000	56,600

RPS Voluntary Allocation Example (continued)

3. Determine PCIA-eligible products by vintage and allocate according to load share

LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total RPS Allocation	% of Total RPS
Total RPS (GWh) *		592	345	3,761	1,589	1,940	728	392	3,206	4,442	42	27	226	0	17,290	100%
SCE	N/A	392	229	2,492	1,240	1,513	568	306	2,501	3,465	33	21	180	0	12,941	75%
Direct Access	2009	89	52	566	0	0	0	0	0	0	0	0	0	0	708	4%
CCA1	2015	7	4	45	23	28	10	6	45	63	0	0	0	0	231	1%
CCA2	2017	4	2	23	11	14	5	3	23	32	0	0	0	0	116	1%
CCA3	2018	86	50	544	270	330	124	67	546	756	7	5	39	0	2,824	16%
CCA4	2018	3	2	18	9	11	4	2	18	25	0	0	1	0	94	1%
CCA5	2020	11	7	73	36	44	17	9	73	101	1	1	5	0	376	2%





* Source: SCE's public ERRA 2020 Forecast

Proposed Voluntary Auction Revenue Allocation Mechanism

1. Determine PCIA-eligible products to be allocated to each LSE (Table 3 of Allocation)

LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total RPS Allocation
Total RPS (GWh)		592	345	3,761	1,589	1,940	728	392	3,206	4,442	42	27	226	-	17,290
SCE	N/A	392	229	2,492	1,240	1,513	568	306	2,501	3,465	33	21	180	0	12,941
Direct Access	2009	89	52	566	0	0	0	0	0	0	0	0	0	0	708
CCA1	2015	7	4	45	23	28	10	6	45	63	0	0	0	0	231
CCA2	2017	4	2	23	11	14	5	3	23	32	0	0	0	0	116
CCA3	2018	86	50	544	270	330	124	67	546	756	7	5	39	0	2,824
CCA4	2018	3	2	18	9	11	4	2	18	25	0	0	1	0	94
CCA5	2020	11	7	73	36	44	17	9	73	101	1	1	5	0	376

2. Evaluate impact of each LSE's sales elections and pool products for sale. Determine maximum to be sold for prompt year and over 10+ year terms

Sales Elections	% Sold	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total RPS Sales	Max Long-Term Sales*
SCE	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Direct Access	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA1	100%	7	4	45	23	28	10	6	45	63	0	0	0	0	231	58
CCA2	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCA3	50%	43	25	272	135	165	62	33	273	378	4	2	20	0	1412	353
CCA4	100%	3	2	18	9	11	4	2	18	25	0	0	1	0	94	24
CCA5	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total (GWh)		53	31	335	167	204	76	41	337	466	4	2	21	0	**1737**	**434**

* Assumes 25% long-term sales threshold

Proposed Voluntary Auction Revenue Allocation Mechanism (continued)

3. Accept bids to purchase products in Market Offer process

Bid #	Prices	Quantities	Term
Bid 1	$10	400	1
Bid 2	$12	500	10
Bid 3	$8	200	1
Bid 4	$19	50	1
Bid 5	$15	300	10
Bid 6	$14	200	1
Bid 7	$6	1000	1
Bid 8	$1	1500	10
Bid 9	$9	700	1
Bid 10	$7	600	1

4. Order bids by price and accept bids until all quantities have been sold

Selection Order	Bid #	Prices	Quantities (GWh)	Term	Cumulative Long Term	Adjusted LT Quantity	Cumulative Quantity	Adjusted Quantity	Revenue/Yr
Contract 1	Bid 4	$19	50	1	0	0	50	50	$950,000
Contract 2	Bid 5	$15	300	10	300	300	350	300	$4,500,000
Contract 3	Bid 6	$14	200	1	300	0	550	200	$2,800,000
Contract 4	Bid 2	$12	500	10	434	134	684	134	$1,610,769
Contract 5	Bid 1	$10	400	1	434	0	1084	400	$4,000,000
Contract 6	Bid 9	$9	700	1	434	0	1737	653	$5,874,231
Contract 7	Bid 3	$8	200	1	434	0	1737	0	$0
Contract 8	Bid 10	$7	600	1	434	0	1737	0	$0
Contract 9	Bid 7	$6	1000	1	434	0	1737	0	$0
Contract 10	Bid 8	$1	1500	10	434	0	1737	0	$0
Total									$19,735,000

Proposed Voluntary Auction Revenue Allocation Mechanism (continued)

5. Allocate revenues pro-rata amongst LSEs based upon their contribution to pool of products to be sold (from Table 2)

Revenue Allocation	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total RPS Sales
Total RPS Sales (GWh)	53	31	335	167	204	76	41	337	466	4	2	21	0	1737
Total Revenue Allocation	$599,697	$349,486	$3,809,899	$1,895,060	$2,313,667	$868,221	$467,504	$3,823,514	$5,297,582	$43,944	$28,250	$238,175	$0	$19,735,000
SCE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Direct Access	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CCA1	$81,040	$47,228	$514,851	$256,089	$312,658	$117,327	$63,176	$516,691	$715,889	$0	$0	$0	$0	$2,624,950
CCA2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CCA3	$486,241	$283,367	$3,089,108	$1,536,535	$1,875,946	$703,963	$379,057	$3,100,146	$4,295,337	$41,198	$26,484	$223,289	$0	$16,040,671
CCA4	$32,416	$18,891	$205,941	$102,436	$125,063	$46,931	$25,270	$206,676	$286,356	$2,747	$1,766	$14,886	$0	$1,069,378
CCA5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

RPS Transfer Mechanisms

- Transfer of RECs from IOU WREGIS account to Allocatee's WREGIS account by Q2 following flow year, with sufficient time for LSEs to meet compliance obligations
  - RECs will be sourced from any similar PCIA-eligible resources
    - e.g., long-term PCC1
- Transfer of RECs to Buyer's WREGIS account will occur on a monthly basis within 30 days of RECs' creation by WREGIS
- Transfer of GHG-free credit will be effectuated through reporting of debit from IOU and credit to benefiting LSE's Power Content Label through a filing with the CEC*
  - Filed in Q2 following flow year
- IRP
  - Intended for LSEs to receive credit for their eligible allocation shares, less any long-term Market Offer sales, from the vintaged PCIA portfolio in the IRP process
    - Any sales performed by any LSE of its allocated share, or by IOU through portfolio optimization, are treated in accordance with existing IRP rules and requirements

* Subject to CEC regulatory reporting requirements

RPS Power Content Label Forecasting

- IOU will provide the following forecasts of aggregated RPS production by vintaged pool*:
  - Resource IDs for all resources;
  - The aggregated, total year-ahead ERRA forecast;
  - An aggregated, year-ahead forecast of the total production for each of the 12 months;
  - Quarterly updates for remaining balance of year of the monthly total, aggregated production; and
  - IOU will provide past three years of historical, aggregated, hourly production data
- Information must be aggregated to preserve confidentiality
  - Inability to aggregate may prevent provision of forecast or meter data for year N-1

*IOU bears no responsibility to benefiting LSEs for accuracy of forecasts provided

System/Flex RA-Specific Mechanisms

PCIA Phase 2 - Working Group 3

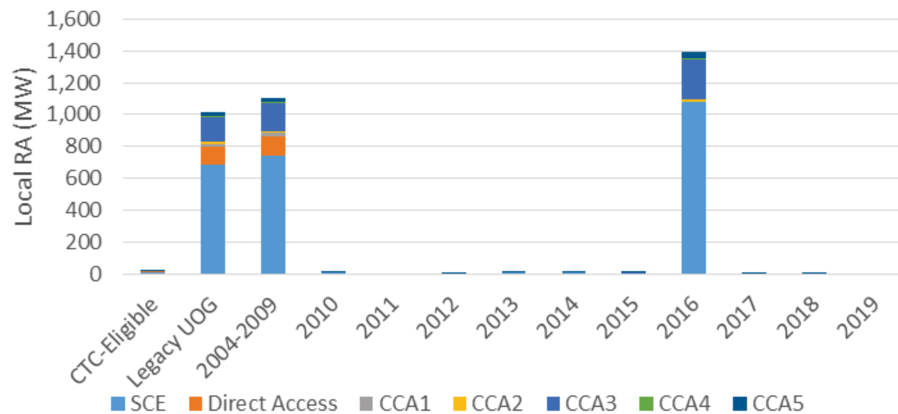
System/Flex RA Voluntary Allocation: "CAM-like" Mechanism

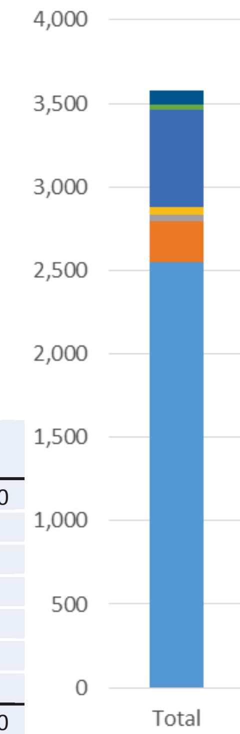
- IOU will show all PCIA-eligible RA resources on its supply plan and for each RA compliance filing
- Annually in the Fall, CPUC will determine appropriate share of each vintage's System and Flex RA positions to be allocated to each LSE for each month of the prompt year
- Annually, concurrently with the publication of the final RA compliance requirements, CPUC will:
  - Issue a letter to IOU indicating quantities of RA debited from IOU positions for allocation purposes; and
  - Issue a letter to each benefiting LSE indicating quantities of RA credited towards LSE's positions
- Each LSE will reflect the PCIA credit/debit within its annual CAISO RA showing
- Actual quantities debited and credited may vary year-over-year, subject to changes in load share, IOU contract management activities, NQC adjustments, etc.
  - Contract management activities are governed through ERRA and AB57, with PRG consultation (as appropriate)
- IOU will maintain responsibility for outages, substitution capacity, penalties, etc.
  - Costs incurred passed through PCIA mechanism, except for any costs disallowed through the IOU's ERRA proceeding

For more information on CAM process, refer to: https://www.cpuc.ca.gov/General.aspx?id=6311
See 2019 Final RA Guide and CAM Allocation links

Local RA Voluntary Allocation Example

LSE Assumptions (Illustrative)	Annual Load (GWh)	Peak Load (MW)	Vintage
SCE	55,000	13,000	N/A
Direct Access	12,500	2,200	2009
CCA1	1,000	360	2015
CCA2	500	225	2017
CCA3	12,000	3,000	2018
CCA4	400	140	2018
CCA5	1,600	450	2020





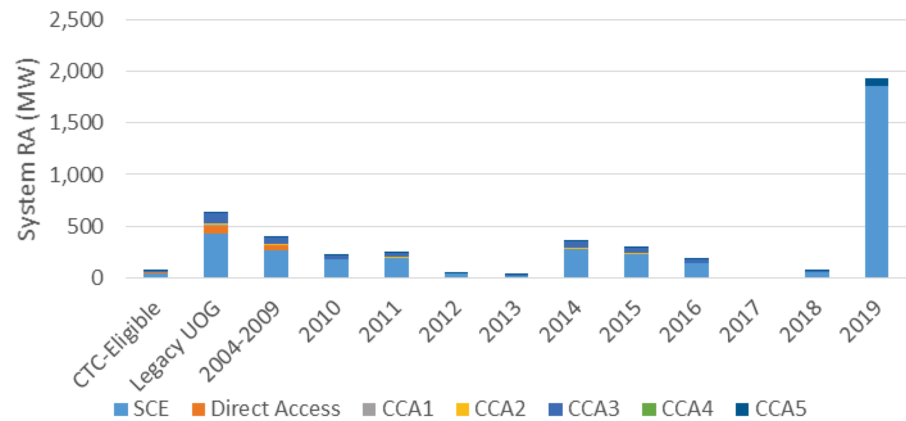
LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SCE	2019	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000
Direct Access	2009	2,200	2,200	2,200										
CCA1	2015	360	360	360	360	360	360	360	360	360				
CCA2	2017	225	225	225	225	225	225	225	225	225	225	225		
CCA3	2018	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	
CCA4	2018	140	140	140	140	140	140	140	140	140	140	140	140	
CCA5	2020	450	450	450	450	450	450	450	450	450	450	450	450	450
Total Peak-Load (MW)		19,375	19,375	19,375	17,175	17,175	17,175	17,175	17,175	17,175	16,815	16,815	16,590	13,450

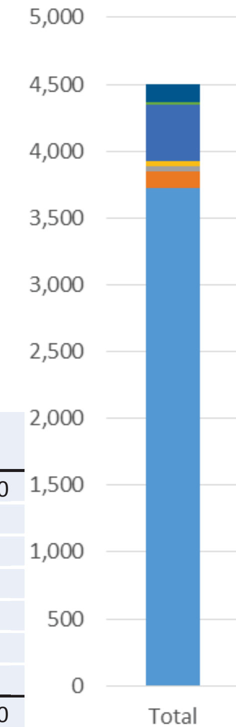
LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total Local RA Allocation	% of Total Local RA
Total Local RA* (MW)		20	1,018	1,102	10	0	3	9	11	8	1,393	1	6	0	3,579	100%
SCE	2019	13	683	739	8	0	2	7	8	6	1,077	1	4	0	2,548	71%
Direct Access	2009	2	116	125	0	0	0	0	0	0	0	0	0	0	243	7%
CCA1	2015	0	19	20	0	0	0	0	0	0	0	0	0	0	41	1%
CCA2	2017	0	12	13	0	0	0	0	0	0	19	0	0	0	44	1%
CCA3	2018	3	158	171	2	0	0	2	2	1	249	0	1	0	588	16%
CCA4	2018	0	7	8	0	0	0	0	0	0	12	0	0	0	27	1%
CCA5	2020	0	24	26	0	0	0	0	0	0	37	0	0	0	88	2%

* Source: SCE's public ERRA 2020 Forecast

System RA Voluntary Allocation Example

LSE Assumptions (Illustrative)	Annual Load (GWh)	Peak Load (MW)	Vintage
SCE	55,000	13,000	N/A
Direct Access	12,500	2,200	2009
CCA1	1,000	360	2015
CCA2	500	225	2017
CCA3	12,000	3,000	2018
CCA4	400	140	2018
CCA5	1,600	450	2020





LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SCE	2019	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000
Direct Access	2009	2,200	2,200	2,200										
CCA1	2015	360	360	360	360	360	360	360	360	360				
CCA2	2017	225	225	225	225	225	225	225	225	225	225	225		
CCA3	2018	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	
CCA4	2018	140	140	140	140	140	140	140	140	140	140	140	140	
CCA5	2020	450	450	450	450	450	450	450	450	450	450	450	450	450
Total Peak-Load (MW)		19,375	19,375	19,375	17,175	17,175	17,175	17,175	17,175	17,175	16,815	16,815	16,590	13,450

LSE	Vintage	CTC-Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total System RA Allocation	% of Total System RA
Total System RA* (MW)		64	643	399	227	250	47	27	360	297	184	0	73	1,928	4,499	100%
SCE	2019	43	432	268	172	189	36	21	272	225	142	0	57	1,863	3,720	83%
Direct Access	2009	7	73	45	0	0	0	0	0	0	0	0	0	0	126	3%
CCA1	2015	1	12	7	5	5	1	1	8	6	0	0	0	0	46	1%
CCA2	2017	1	7	5	3	3	1	0	5	4	2	0	0	0	31	1%
CCA3	2018	10	100	62	40	44	8	5	63	52	33	0	13	0	428	10%
CCA4	2018	0	5	3	2	2	0	0	3	2	2	0	1	0	20	0%
CCA5	2020	1	15	9	6	7	1	1	9	8	5	0	2	65	129	3%

* Source: SCE's public ERRA 2020 Forecast

Illustrative Voluntary Auction Valuation Mechanism

1. Determine Sales Quantities

Amounts for Sale	Month	Quantity (MW)
July	7	300
August	8	350
September	9	250

2. Receive Bid Prices and Quantities

Offer	Term	Month	Price ($/kW-mo)	Quantity (MW)
1	July	7	$4.00	100
2	July	7	$6.00	50
3	July	7	$5.50	300
4	August	8	$2.50	200
5	August	8	$4.25	100
6	August	8	$5.10	50
7	September	9	$3.50	150
8	September	9	$4.50	200
9	September	9	$3.25	50
10	Q3	7	$4.75	200
10	Q3	8	$4.75	200
10	Q3	9	$4.75	200

Illustrative Voluntary Auction Valuation Mechanism (continued)

3. Rank Bids by Price

Offer	Term	Month	Price ($/kW-mo)	Quantity (MW)
2	July	7	$6.00	50
3	July	7	$5.50	250
10	Q3	7	$4.75	200
1	July	7	$4.00	100
6	August	8	$5.10	50
10	Q3	8	$4.75	200
5	August	8	$4.25	100
4	August	8	$2.50	200
10	Q3	9	$4.75	200
8	September	9	$4.50	200
7	September	9	$3.50	150
9	September	9	$3.25	50

4. Select Bids up to Quantity Available, While Maximizing Revenues

Selected Offers	Term	Month	Price ($/kW-mo)	Quantity (MW)	Revenue ($000)
2	July	7	$6.00	50	$300.00
3	July	7	$5.50	50	$275.00
10	Q3	7	$4.75	200	$950.00
6	August	8	$5.10	50	$255.00
10	Q3	8	$4.75	200	$950.00
5	August	8	$4.25	100	$425.00
10	Q3	9	$4.75	200	$950.00
8	September	9	$4.50	50	$225.00
Total					**$4,330.00**

Appendix B

INFORMAL COMMENTS TO THIRD WORKSHOP PRESENTATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

ALLIANCE FOR RETAIL ENERGY MARKETS INFORMAL COMMENTS ON PCIA WORKING GROUP 3 MEETING #3

Scott Olson, Director, Western G&RA
DIRECT ENERGY BUSINESS, LLC
44 Montgomery St., 22nd Floor
San Francisco, CA 94104
Telephone: (510) 778.0531
scott.olson@directenergy.com

On Behalf Of the
ALLIANCE FOR RETAIL ENERGY MARKETS

28 October 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

ALLIANCE FOR RETAIL ENERGY MARKETS PCIA WORKING GROUP 3 WORKSHOP #3

The Alliance for Retail Energy Markets ("AReM") appreciates the opportunity to provide these informal comments on topics introduced in Workshop #3 of Working Group #3 ("WG3"), conducted on 17 October 2019 in San Francisco, California. AReM's comments below are focused on the Local RA allocation proposal, proposed options for PCIA Ratemaking, and remaining clarifications needed.

AReM understands that the important work of determining how to get the IOU resource portfolios in line with the amount of load they are serving is intended to be addressed in future WG3 meetings and believes that is the most important work that this WG should be addressing. The efforts to construct voluntary resource allocations to LSEs paying a fair market value for them (a model very similar to the IOU Portfolio Allocation Mechanism introduced earlier in this proceeding and rejected) followed by an auction of unallocated resources is unduly complicated and inferior to a simpler mechanism that would solely auction off excess resources. That said, the revision presented in Workshop 3 for allocations based on vintage peak-load share instead of PCIA contribution levels is an improvement over previous proposals, but AReM continues to believe that this WG has so far missed the mark by focusing on short-term sales and allocations instead of focusing on approaches that will result in getting IOU resources in line with the amount of load they are serving and expected to serve over the long term.

If the short-term proposals are nevertheless to be implemented, AReM urges that the following issues be addressed.

Local RA Allocation Proposal

As stated in previous comments, AReM considers the proposed allocation proposal to be inferior to a mechanism that would auction off the excess Local RA to willing buyers. As an alternative to this uncompetitive, non-market based proposal, the IOUs should continue to make Local RA available to all entities through an auction first, until longer term divestiture by the IOUs of their excess supply can be finalized. While the WG3 leads state that the reason for the allocation is to get around issues related to the buffer and uncertainty tranches, there is no reason that the same amount of PCIA-eligible resources cannot be sold in an auction instead of through an allocation process.

While all other resource attributes (System/Flex RA, RPS, and GHG-Free resources) are being allocated on a voluntary basis, WG3 continues to propose that Local RA allocation be mandatory. If an allocation process occurs, AReM does not believe that there is a need to treat Local RA differently from other resource allocations and asks the WG3 leads develop an approach where Local RA will also be allocated on a voluntary basis only. In addition, mandatory allocations run counter to Commission direction for what the Working Groups should consider[1], as outlined by DACC in their comments of 9 August.

[1] D.18-10-019, Decision Modifying the Power Charge Indifference Adjustment Methodology, at p. 96.

Under the WG3 proposal, entities not needing their full allocation could sell to others, but that approach just exchanges one problem for another. Much like the IOUs today, there is no guarantee that those entities will sell any excess they have, will have time to sell any excess they have given when the allocation occurs, that those entities will not keep the excess as a "buffer" or for "uncertainty", or that those entities will not use allocated Local for System or Flex RA needs.

In addition, many LSEs may not need their allocation, especially in areas with increasing levels of CAM allocations. For example, all non-IOU LSEs are seeing considerably lower LA Basin Local RA requirements beginning in 2022 due to new CAM allocations. A mandatory allocation could then force non-IOU LSEs to take and pay through the PCIA for resources that they do not need.

Another major issue with any RA allocation followed up by an auction is the timing of the entire process. As outlined in the workshop (slide 23), timing of the yearly RA process is very tight; in the absence of modifications of the RA timelines, the process may become unworkable. For these resources to be tradable and for LSEs to optimize their own portfolios, the allocated resources should be provided to LSEs as soon as yearly obligations are finalized so that they can be used by the end of the year ahead compliance period. This tightness is yet another reason why an auction process without allocation is recommended.

Finally, the WG leads need to address how these allocations will work in an environment with a residual or full central buyer for Local RA. While it is unclear at this stage the type of central buyer that will be implemented by the Commission for Local RA, consideration should still be made for how the proposals will be adapted and integrated under each of these central buyer options. If a central buyer will lead to material changes to the allocation approach being considered by this WG3, that would be useful information for stakeholders to consider.

PCIA Ratemaking

The workshop presented two options for changes to PCIA Ratemaking to support the proposals developed by WG3. Option 1 keeps the PCIA approach generally the same as today, with credits given to individual LSEs which choose to have the IOU sell their allocation in an auction. Option 2 decreases the PCIA costs by the RA and RPS Market Price Benchmark ("MPB") for resources available for allocation, with LSEs then paying the IOU for the RA and RPS attributes of the resources that it accepts in the allocation.

AReM prefers Option 2. First, Option 2 appropriately follows cost causation principles. Under this option, entities that accept their allocation will have specific costs imposed on them for this allocation, as opposed to Option 1 where costs are imposed on all LSEs through the PCIA. Second, Option 2 allows LSEs to more easily compare options to meet their procurement requirements. Under Option 2, LSEs will know what their costs will be if they accept their allocation (either the MPB or an Auction Price Benchmark ("APB")) and can compare this cost with other options in the market to meet their needs. This is not the case in Option 1 where the value that LSEs will be credited with will not be known until the auction is held later. This uncertainty for the value of their allocation makes it more difficult to compare versus other market offers.

AReM members are focused on reducing their PCIA exposure, having more control over our procurement, and moving resources out of IOU control. Option 2 for assessment of future PCIA values and assigning costs best helps to meet these goals relative to Option 1.

Long-Term Sales Clarifications Required

In review of the recent WG3 documents, AReM requests clarification on two topics related to long-term RPS sales:

- **Long-term Sales Cap:** It is unclear what is meant when the WG3 leads state that the cap will be "applied to the lesser of LSE's (a) total allocation share or (b) sales election" and how these two items differ. Also, it is unclear how a proposed 25% cap was developed, if there were any analytics around the basis for this number, and what other options were considered.
- **Alignment with RPS Rulemaking:** The WG3 leads identify 2 options for long-term allocations: 1) long-term attributes preserved regardless of term of allocation and 2) 10 year+ allocations to preserve long-term attributes. Option 1 runs counter to current RPS rules (and potentially the intent of SB 100 legislation) that contracts must be for 10 years or longer to count for long-term RPS obligations, so it is unclear how the SCE and Commercial Energy proposal will work in light of these restrictions. Option 2 appears to be the only option that aligns with current RPS compliance rulemaking. The RPS long-term contracting rules should not be changed now for the benefit of entities not prepared to undertake long-term contracting risk.

Remaining Concerns

AReM believes that this WG has missed an opportunity to focus on approaches that will result in getting IOU resources in line with the amount of load they are serving and expected to serve over the long term, rather than focusing on short-term sales and allocations. While the WG3 leads have stated that these issues are to be considered before Workshop 4, this leaves little time to review and provide input before the release of the Final Report on January 30, 2020.

Other items remain outstanding that need to be addressed are the following:

- **Tracking:** How will these credits be tracked to assure attributes are retired and not double counted? Without a robust accounting mechanism for these credits, the proposal should not move forward.
- **Acceptance by Regulatory Agencies:** Both the CEC as part of accounting for the Power Content Label ("PCL") and the Commission's IRP GHG Net Short do not credit RECs not associated with physical power delivery in these programs; each program wants to see information on the generation source of the physical power purchased by each LSE. Similarly, it is unclear to AReM if these GHG-Free attributes that will be allocated, with no physical power or contracts changing hands, will be accepted by either the CEC as part of the PCL or the Commission as part of the IRP. Affirmation should be presented from both agencies, along with information as to whether any new rulemaking will be required to allow this new attribute to be included in each program.

AReM asks that these issues be addressed and resolved before the final report.

Respectfully submitted,

Scott Olson, Director, Western G&RA
DIRECT ENERGY BUSINESS, LLC
44 Montgomery St., 22nd Floor
San Francisco, CA 94104
510.778.0531
scott.olson@directenergy.com

On Behalf Of the
ALLIANCE FOR RETAIL ENERGY MARKETS

28 October 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

DIRECT ACCESS CUSTOMER COALITION INFORMAL COMMENTS ON WORKING GROUP #3 THIRD WORKSHOP

Mark Fulmer
MRW & ASSOCIATES
1736 Franklin St. Suite 700
Oakland, CA 94612
Telephone: (510) 834-1999
mef@mrwassoc.com

Consultant to
DIRECT ACCESS CUSTOMER COALITION

Daniel W. Douglass
DOUGLASS & LIDDELL
4766 Park Granada, Suite 209
Calabasas, California 91302
Telephone: (818) 961-3001
douglass@energyattorney.com

Attorney for the
DIRECT ACCESS CUSTOMER COALITION

October 28, 2019

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

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

**DIRECT ACCESS CUSTOMER COALITION INFORMAL COMMENTS
ON WORKING GROUP #3 THIRD WORKSHOP**

The Direct Access Customer Coalition[1] ("DACC") offers herein its informal comments on topics introduced in Meeting #3 of Working Group #3 ("WG3") that was held on October 17, 2019 at the Commission Auditorium.

DACC appreciates the efforts undertaken by Southern California Edison, California Community Choice Association and Commercial Energy to develop the materials and discussion topics considered at the workshop. DACC's comments on the last workshop noted its grave concerns with the application of a cost allocation mechanism ("CAM")-like default allocation of resource adequacy ("RA") and renewable portfolio standard ("RPS") products and costs to all customers. DACC is grateful to see that the Working Group leaders have, for the most part, moved away from these mandatory allocations of costs and attributes.

However, DACC notes that the direct allocation of local RA costs and attributes appears to persist. DACC continues to maintain that any excess local RA should be made available to other load-serving entities and not forced upon their customers.

---

[1] DACC is a regulatory advocacy group comprised of educational, governmental, commercial and industrial customers that utilize direct access ("DA") for all or a portion of their electrical energy requirements. In the aggregate, DACC member companies represent over 1,900 MW of demand that is met by both DA and bundled utility service and about 11,500 GWH of statewide annual usage.

DACC members strongly prefer interacting with their electric service providers ("ESPs") for all products and services. As such, DACC strongly prefers cost allocation "Option 2," wherein only the stranded cost of the IOUs' portfolios are in the PCIA, including both RA and RPS.

If a DA customer's ESP finds it preferable to accept an allocation of RA or RPS products at the IOU's cost, then it should be able to do so, and if not, then it should be able to decline this option. Option 1, with the automatic allocation of products to a DA customer's ESP adds a layer of opacity to the DA customer's ESP relationship and has the potential to greatly increase the PCIA. DACC opposes both of these outcomes.

Respectfully submitted,

Mark Fulmer
MRW & ASSOCIATES

Consultant to
DIRECT ACCESS CUSTOMER COALITION

Daniel W. Douglass
DOUGLASS & LIDDELL

Attorney for the
DIRECT ACCESS CUSTOMER COALITION

October 28, 2019.

INFORMAL COMMENTS OF THE AMERICAN WIND ENERGY ASSOCIATION OF CALIFORNIA AND THE LARGE-SCALE SOLAR ASSOCIATION ON PCIA WORKING GROUP 3 OCTOBER 17th WORKSHOP

October 28, 2019

AWEA-California and LSA appreciate this opportunity to provide informal comments on the working group 3 proposals for an allocation mechanism within the PCIA framework. AWEA-California and LSA represent much of the utility-scale renewable energy industry in California, and our members hold many of the existing contracts with the IOUs for RPS-eligible energy and capacity. Members of both organizations strive to develop utility scale renewable energy projects that provide the most value to ratepayers. AWEA-California and LSA support the State's efforts to develop a diverse portfolio of clean capacity that addresses RPS needs and best contributes to resource adequacy needs.

In light of the rapid growth of CCAs, there is clearly a need to balance supply and demand. AWEA-California and LSA are supportive of changes to the PCIA that would ensure that the CCAs and ESPs that are paying the PCIA receive product value from the IOUs portfolio. If properly structured, a PCIA allocation mechanism will provide needed certainty to the market and will provide greater stability as the state seeks to build new clean capacity that achieves IRP, RPS, Resource Adequacy requirements.

AWEA-California and LSA are generally supportive of the party proposals to develop new innovative mechanisms for allocating different product types. In particular, it is our understanding that all of the proposals discussed at the October 17th workshop would account for sellers' rights by not requiring modification or assignment of existing PPAs. The need to account for sellers' rights was among the guiding principles established in the first phase of this proceeding. We believe the concept of having the IOUs remain financially responsible and continue to serve as the scheduling coordinator is a reasonable way to adhere to the Commission's guiding principles for this proceeding.

We also appreciate the parties' efforts to develop proposals that would account for the complexities of the various regulatory programs affecting buyers. One of the issues debated during the October 17th workshop was the question of whether long term contracts retain their "long term" status when a CCA or ESP enters into a new contract to receive a slice of the IOU's portfolio. At the CCA/ESP's option, this "slice" may include PCC-1 RECs, presumably generated from a long-term contract between the IOU and the seller. The question is whether a one year contract between the CCA/ESP and the IOU to receive that slice will satisfy the long term contracting requirements applicable to that CCA or ESP.

The long term RPS contracting requirement is codified in Section 399.13(b) of the Public Utilities Code:

> *A retail seller* may enter into a combination of long- and short-term contracts for electricity and associated renewable energy credits. Beginning January 1, 2021, at least 65 percent of the procurement *a retail seller counts* toward the renewables portfolio standard requirement of each compliance period shall be from *its contracts of 10 years or more* in duration or in its ownership or ownership agreements for eligible renewable energy resources. (emphasis added)

The statute clearly applies to individual load-serving entities and directs the Commission to evaluate whether the entity submitting an RPS compliance plan has entered into a contract that is 10 years or more. A proposal to transfer RECs through a one-year contract between a CCA/ESP and the IOU would not comport with Section 399.13(b) because the contract the CCA/ESP points to in its RPS compliance filing is only one year. Under the proposal discussed at the October 17th workshop, the CCA/ESP would not have privity of contract with the parties of any contracts in the IOUs' portfolios. The CCA/ESPs would only have privity of contract with the IOUs and that contract would not meet the requirements of Section 399.13(b).

In addition, the October 17th workshop proposal for a one-year RPS contract structure would also be inconsistent with the Commission decisions implementing Section 399.13(b). For example, in D.17-06-026, the CPUC evaluated the circumstances under which certain variations of contract structures comport with Section 399.13(b). It is important to note that in this and other decisions implementing the long-term contracting requirement, the Commission's focus is on the contracting practices of the individual LSE submitting the RPS compliance plan, not the upstream contracts.

D.17-06-026 specifically contemplates contract structures analogous to those discussed at the October 17th workshop – i.e., "repackaged contracts". A repackaged contract is one in which "a long-term contract for a large volume of generation is divided into smaller pieces, with the pieces being sold to several different parties."[1] The Commission concludes that "[s]uch contracts may be used to meet the LT requirement, so long as they are truly long term, i.e., the retail seller's contract for its repackaged share of the generation has a duration of at least 10 years."[2] In the

[1] D.17-06-026 at p. 21.
[2] *Id.*

context of the PCIA, the rules in D.17-06-026 would apply to a CCA or ESP taking a repackaged slice of the IOUs RPS portfolio. A CCA or ESP taking a slice of RPS energy/RECs would only be able to claim compliance with the long term contracting requirement if its contract with the IOU for that slice is at least ten years. Thus, in order to move forward with a proposal for a one year slice that satisfies the long term contracting requirement, the parties would need to pursue statutory amendments to Section 399.13(b) and the Commission would need to re-interpret that amended statute.

For these reasons, the parties should consider enabling PCIA allocation contract structures that adhere to existing statutory language of Section 399.13(b). AWEA-California and LSA look forward to continuing to participate in this process and support the parties' efforts to balance supply and demand for all energy, capacity and environmental products through a PCIA allocation mechanism.

Dated: October 28, 2019

Respectfully submitted

/s/ Shannon Eddy

Shannon Eddy
Executive Director
Large-scale Solar Association
2501 Portola Way
Sacramento, CA 95818
Tel: 415-819-4285
E-Mail: shannon@large-scalesolar.org

/s/ Danielle Osborn Mills

Danielle Osborn Mills
Director, AWEA-CA
Renewable Energy Strategies
1970 Meadow Oak Lane
Meadow Vista, CA 95722
Tel: (916) 320-7584
E-Mail:
danielle@renewableenergystrat.com

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE
PCIA PHASE 2, WORKING GROUP #3, WORKSHOP #3

M. GRADY MATHAI-JACKSON
KRISTIN D. CHARIPAR

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 973-5520
E-Mail: grady.mathai-jackson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 30, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE
PCIA PHASE 2, WORKING GROUP #3, WORKSHOP #3

Pacific Gas and Electric Company ("PG&E") provides the following informal comments on the Power Charge Indifference Adjustment ("PCIA") Order Instituting Rulemaking ("OIR") Phase 2, Working Group Three, Workshop #3 held on October 17, 2019 (the "Workshop"). While PG&E appreciates the work by Southern California Edison Company ("SCE"), the California Community Choice Association ("CalCCA") and Commercial Energy, collectively the Co-Leads, to develop an initial framework for the allocation of system, local and flexible resource adequacy ("RA"), greenhouse gas ("GHG")-free, and renewables portfolio standards ("RPS") attributes, PG&E does not support the market offer component of the proposal for the reasons described below and has specific concerns with other elements of the proposal. PG&E looks forward to providing additional feedback on the proposals as more details, including implementation details, are developed as part of the working group process.

I. THE INVESTOR-OWNED UTILITIES SHOULD CONTINUE TO OPTIMIZE THE PORTFOLIO ON BEHALF OF BOTH BUNDLED SERVICE AND DEPARTING LOAD CUSTOMERS

During the Workshop, the Co-Leads provided general concepts for the voluntary allocation and market offer ("VAMO") proposals for RPS and system and flexible RA attributes.[1] PG&E supports the general concept of a residual VAMO with the understanding that the investor-owned utilities ("IOUs") will continue to perform portfolio optimization activities

[1] *See* PCIA Phase 2-Working Group 3 Presentation, October 17, 2019, Slide 11.

prior to the annual VAMO activity. PG&E appreciates the Co-Leads in affirming that the VAMO proposal will preserve the IOUs' ability to optimize its portfolio, including through contract assignment, divestiture of resources, contract re-negotiation or through the sale of RA and RPS attributes, and that the VAMO proposal will apply only to residual PCIA-eligible attributes.

To facilitate portfolio optimization or "portfolio right-sizing" activities, PG&E recommends that the Co-Leads restrict the allocation and market offer mechanisms that result in "binding" the IOUs and preventing activities outside of the VAMO to optimize the portfolio in any way. For example, an allocation of local RA attributes to PCIA-eligible load serving entities ("LSEs") occurring beyond the prompt year should not prevent the respective IOU from engaging in portfolio optimization activities (e.g. re-negotiation of contracts, divestiture of resources, longer term sales, etc.) outside of the VAMO activity that would offset costs for all customers paying the PCIA (both bundled service and departing load customers). If an IOU determines it is beneficial to re-negotiate a contract, re-assign a contract or physically sell a local RA resource, a forward year allocation resulting from VAMO should not restrict the IOU from undertaking or delaying that activity until a timeframe when an allocation for LSEs has not yet occurred.

PG&E understands the Co-Leads will provide additional details at the next Working Group Three workshop on how "portfolio right-sizing" inter-plays with the VAMO proposal and looks forward to providing feedback as more details are developed.

II. THE ALLOCATION OF ATTRIBUTES SHOULD BE ON A SHORT-TERM BASIS AND RETAIN LONG-TERM ATTRIBUTES

Under the VAMO proposal, the Co-Leads detailed two allocation structures for RPS to preserve the long-term (10+ years) attributes. SCE and Commercial Energy proposed that the allocation structure preserve long-term attributes regardless of the term of the allocation, including for an allocation on a prompt-year only basis. On the other hand, CalCCA proposed that the allocation structure require an LSE to accept a 10-plus year RPS allocation to preserve long-term attributes.

PG&E supports the SCE and Commercial Energy proposal, and recommends that the allocation structure of RPS attributes:

- maintain their long-term attributes;
- be on a prompt-year only basis;
- be set on a percentage basis rather than by a set quantity.

Long-term allocations would impede IOUs' portfolio optimization activities and create unnecessary risks.

To be clear, while PG&E supports an allocation structure for the prompt-year only and should maintain its long-term attributes, PG&E believes that any further short-term sales of RPS attributes that occur outside of the VAMO proposal or as a part of the VAMO auction (or market offer) mechanism should not maintain its long-term attributes even if that attribute would have been associated with a long-term allocation.

III. THE ALLOCATION PROPOSAL FOR RESOURCE ADEQUACY CREATES ADDITIONAL RISK ON THE INVESTOR-OWNED UTILITY FOR REPLACEMENT CAPACITY

PG&E generally supports the concept of allocating under the VAMO proposal, including allocation of system and flexible RA on a voluntary basis and of local RA on a mandatory basis to all PCIA-eligible LSEs, and appreciates the Co-Lead's efforts in putting forward the proposal. PG&E understands the allocation proposal for RA intends for the RA attributes to be allocated to LSEs in a fashion that is similar to the process established for the cost allocation mechanism ("CAM"). PG&E has some concerns that, under this proposal, the respective IOU would "show" the RA capacity on behalf of all LSEs without consideration of a specific resource's actual availability (e.g. hydrological conditions, planned maintenance outage or unplanned outage). PG&E requests that the Co-Leads provide a specific proposal for how all potential RA penalties and compliance risks will be shared between the IOU, energy service providers ("ESPs") and community choice aggregators ("CCAs") under this proposal.

PG&E is concerned that, given this background, the current VAMO proposal for RA attributes may not appropriately and equitably share compliance risk. As a scheduling coordinator in the CAISO's energy market, PG&E, under CAISO Tariff Section 9 and Section 40.9.3., will retain replacement obligations for RA capacity shown that is on planned maintenance outage or unplanned outage. In the case of an outage, the availability standard penalties (e.g. resource adequacy availability incentive mechanism ("RAAIM")) can be equitably shared under the current PCIA structure, but some penalties and risks may be impossible to share across customers and across LSEs. For example, under current rules, the potential Federal Energy Regulatory Commission ("FERC") investigation of non-compliance or operational risks associated with a CAISO-cancelled outage due to insufficient replacement capacity would be solely borne by the IOU. Additionally, while conceptually it makes sense to share non-compliance penalties (e.g., Capacity Procurement Mechanism ("CPM"), Commission RA compliance penalties), it is not clear how these penalties can be allocated through PCIA rates.

In addition to the issue of unshared compliance risk, it may be difficult and costly to procure replacement capacity due to an outage in today's tightened RA market and in a short-term timeframe. As mentioned in its informal comments to the PCIA Phase 2, Working Group Three, Workshop #2 held in July 2019, PG&E needs to retain capacity within its portfolio should CAISO require replacement capacity for a specific resource outage. PG&E is concerned that the VAMO proposal would not allow for the retention of capacity needed for resource outage replacement even though it may be required under the CAISO Tariff.[2]

Because the current VAMO proposal shifts risks to the IOU, but provides certainty in the allocations from an uncertain portfolio of resources that the IOU is left to manage, PG&E recommends that the Co-Leads consider accounting for unit-specific resource availability as part of the RA attributes that would be allocated to PCIA-eligible LSEs. Specifically, the capacity of

[2] *See* CAISO's Business Practice Manual for Reliability Requirements, Version 44, Section 9 "Resource Adequacy Substitution".

the unit-specific resource that is unavailable would not be allocated to PCIA-eligible LSEs. This could address that additional risks and help to ensure that costs are not shifted to bundled service customers from departing load as required by statute.[3]

IV. THE PROPOSAL CAN BE MADE MORE EFFICIENT AND LESS COMPLEX BY ENABLING EACH LOAD-SERVING ENTITY TO SELL ITS OWN PCIA ATTRIBUTES IF IT DOES NOT WANT TO KEEP THEM

During the Workshop, the Co-Leads expanded on the VAMO proposal and provided additional details since the PCIA Phase 2, Working Group Three, Workshop #2 held in July 2019. PG&E appreciates the Co-Lead's efforts, specifically on the proposed framework to allocate PCIA-eligible portfolio attributes; however, PG&E believes that the market offer mechanism (previously known as the auction mechanism) is overly complex and sales would be better if performed by each LSE, after the allocation of attributes, where those LSEs could consider the sales in the context of their whole portfolios. In this section, PG&E provides a few items of notable concern, including: (1) the extensive administrative burden placed on the IOUs and Commission to monitor and manage the market offer mechanism; and (2) the lack of any compelling argument for why the IOUs need to sell and manage the allocated attributes on behalf of PCIA-eligible LSEs.

A. The Current Proposal Results in Extensive Administrative Burden Being Placed On The IOUs and Commission to Monitor and Manage the Market Offer Mechanism

Under the proposed market offer mechanism, the IOUs would be required to track, manage and monitor the PCIA-eligible attributes, each with a distinct structure, of the portfolio for all LSEs. For example, GHG-free attributes involve an all-or-nothing allocation with no market offer, system and flexible RA involves a 10 percent increment allocation with a market offer and local RA involves a mandatory allocation with no market offer. Furthermore, the VAMO proposal introduces differing allocation terms (e.g. one year, 10+ years, or for the underlying term of the contract, etc.) and respective caps on long-term sales from the market

[3] *See* Cal. Pub. Util. Code §§ 365.2 and 366.3.

offer mechanism. Given that the IOUs will be conducting portfolio optimization activities outside of the VAMO proposal and could likely be a participant in VAMO, the current complexities and lack of uniformity among the attributes imposes administrative burden and could result in associated risks of litigation. The compressed timeline for market offer sales impedes on other IOU procurement processes, unduly complicates IOU procurement activities and poses significant administrative burden on the IOUs. The IOUs would likely need to create separate teams to perform the market offer sales, resulting in additional and unnecessary costs. Further, the IOU's actions taken on behalf of other LSEs, and the IOU's management of its contract portfolio more generally, will also be subject to review and disagreement, potentially resulting in the need for new or expanded regulatory proceedings and other litigation. PG&E requests that the Co-Leads step back and review the complexity of the current proposal and consider a simpler approach that would be easier to implement, maintain, and preferable to all.

B. Non-IOU LSEs Should Sell Attributes On Their Own Behalf

The VAMO proposal does not appear to offer a compelling argument or benefit for why the IOUs should be the agent to resell the PCIA-eligible portfolio attributes on behalf of other LSEs. Parties have expressed concerns in another proceeding on the IOUs serving in a similar role as a centralized procurement entity on behalf of other LSEs. For example, in the RA OIR proceeding (R.17-09-020), the CalCCA argued that IOUs "…selling RA in the market could present an obvious conflict of interest and enable self-dealing to the benefit of the IOU's bundled service." PG&E recommends that the Co-Leads consider whether they can develop a paradigm that allows the non-IOU LSEs to sell portfolio attributes allocated to them on their own behalf. PG&E also notes that, in the RA proceeding, development of a central procurement entity is a current topic. To the extent a central procurement entity exists, PG&E requests the Co-Leads to consider whether use of such an entity might modify the VAMO proposal.

V. AN ALLOCATION OF ALL ATTRIBUTES, INCLUDING THE BROWN POWER ATTRIBUTE, MUST BE CONSIDERED

During the Workshop, the Co-Leads outlined the mechanisms on the allocation of the PCIA-eligible portfolio, including the allocation of RA, RPS and GHG-free attributes. PG&E notes that the PCIA-eligible portfolio also contains an attribute that has not been considered by the Co-Leads up to this point. Thus, PG&E recommends that the Co-Leads consider how the natural gas or "brown" power attribute of the PCIA-eligible portfolio would be equitably allocated among the LSEs. Any allocation mechanism of the PCIA-eligible portfolio that is ultimately adopted by the Commission should ensure all LSEs equitably receive all attributes.

VI. ALLOCATION OF GHG-FREE ATTRIBUTES MUST BE COORDINATED WITH THE INTEGRATED RESOURCE PLANNING FILING REQUIREMENTS

PG&E supports the general direction of the Co-Leads and the allocation proposal for GHG-free attributes as presented at the Workshop, provided that the allocation mechanisms equally address the GHG content of the remaining "brown" portfolio as discussed above. PG&E understands the allocation proposal for GHG-free attributes intends for the attributes to be allocated to LSEs, which would have an option to voluntarily accept or deny the available pool (non-nuclear or nuclear) of GHG-free attributes. All GHG-free attributes that are not accepted by LSEs would then be re-allocated to the LSEs who accepted the allocation from the first round of allocations. The allocation of GHG-free attributes would be done on an annual basis and would not be bound by the prior year's accepted or denied allocation of attributes.

PG&E recommends that the Co-Leads consider how the allocation of GHG-free attributes, among others, should be coordinated with the integrated resource planning ("IRP") filing requirements. The primary concern for PG&E is that the entire portfolio's content be allocated and shown in IRP filings (i.e. that allocations not be stranded or double counted) so that a clear picture of the state's emissions can be presented to the Commission as part of the IRP process. PG&E recommends that the Co-Leads consider how to mitigate any uncertainties surrounding how allocations should be considered through the IRP process so that all LSEs understand how this proposal would carry through to that proceeding.

VII. PG&E SUPPORTS RATEMAKING OPTION ONE BECAUSE IT MINIMIZES RATEMAKING AND ADMINISTRATIVE COMPLEXITY

During the Workshop, the Co-Leads presented two Ratemaking Options for the VAMO proposal. Of the two options, PG&E prefers Ratemaking Option 1 because it minimizes the ratemaking and administrative complexity, which is not insignificant, and arrives at a fair allocation of the costs and benefits of the portfolio. Under Ratemaking Option 1, when an LSE takes the allocation, the attribute values for RPS and RA in the indifference calculation would be zero, which differs from today's construct where an RPS and RA attributes are valued at the attributes' approved market price benchmark ("MPB"). With this approach, there would be no further need for the Commission to review and calculate MPBs for sold and to further quantify unsold portions of the portfolio, both of which can be administratively burdensome and potentially contentious. Further, the Commission has not yet determined how to benchmark or value long-term RPS sales and there would be no need to pursue that further. Under this approach if an LSE decides to sell its allocated attributes instead of taking the allocation, any realized revenues are returned to the LSE and would not impact the indifference calculation and resulting PCIA rates. The PCIA rates would remain the same as rates calculated under the allocation, which sets the attribute value at zero in the indifference calculation. Although the PCIA rates under Ratemaking Option 1 will be higher than they are under today's construct, the higher PCIA rate reflects the fact that the customer is paying directly for the allocated attributes, which preserves the portfolio value for customers and they receive the value of any allocated amount of a sale, should they choose to do so.

As presented by the Co-Leads, Ratemaking Option 2 would result in a PCIA calculation that is nearly identical to today's calculation in that allocated attributes would be valued at the Commission-approved PCIA MPB for those attributes and auction (or market offer) results would be valued based on the transacted price. There was a sub-bullet in the presentation that is a problematic outcome, if adopted.

Specifically, under Ratemaking Option 2, LSEs taking the allocation would pay the IOUs the market value for the portfolio based on the PCIA MPB which would then be credited to the

Portfolio Allocation Balancing Account. In the case where the LSE decides not to take its attribute allocation, it would instead offer the attributes for sale through the market offer mechanism and the proceeds would then be credited against the indifference calculation and the allocated attributes would be valued at the PCIA MPB for those attributes. This ratemaking construct is very similar to how the indifference amount and resulting PCIA rates are determined today where third-party sales are netted against total costs, less CAISO market revenues, less the value of the retained attributes calculated using an MPB, with the exception that the attributes would be allocated rather than retained. However, the sub-bullet in the presentation also suggested that there may be a preference that the MPB be set based on the auction (or market offer) results only, and this proposal was supported by a statement that LSEs would be indifferent to taking allocation or monetizing allocation through sales if the MPB used in Ratemaking Option 2 were set based on the "Auction Price Benchmark." The Commission has previously determined how to set MPBs and noted the need to potentially develop long-term RPS benchmarks as well. There is no requirement that LSEs be indifferent when deciding whether they take the allocation or have the IOUs sell the allocation on their behalf. There is, however, a statutory requirement that customers are indifferent when setting PCIA rates, and customer indifference can only be achieved when the market value is calculated using a true MPB. Valuing the portfolio attributes based on what could be a very thin amount of trading activity conducted through the VAMO proposal almost guarantees that the auction (or market offer) prices would not be reflective of the actual market activity, much of which will be transacted outside of these VAMO proposal. Instead, the auction (or market offer) results should be reported to the Commission along with other market transaction activity, as required by the protocols established in Decision 19-10-001, and folded into the MPB calculation.

Customer indifference can only be achieved if the portfolio's attribute value is based on actual market prices and activity, which was the subject of the debate in Phase 1 of the PCIA OIR. There is no reason to revisit how to value retained or allocated attributes – the values of these attributes should be based on a broad survey of actual market transactions as approved in

Decision 19-10-001. To do otherwise will result in cost shifts between bundled service and departing load customers.

VIII. ADDITIONAL ISSUE FOR CONSIDERATION

PG&E recommends the following additional issue for consideration related to the VAMO proposal as presented by the Co-Leads in Working Group Three: implementation of VAMO may require changes to existing rules and new legislation.

PG&E notes that the PCIA-eligible IOUs' portfolios represent a significant portion of the state's generation and contain products subject to legislative restrictions and regulated by multiple state agencies or organizations. As such, it is important for the proposed paradigm to outline the regulatory rule changes and/or legislation required to: (1) maintain the value of the portfolio; and (2) ensure that its allocation does not impair California's ability to meet its energy and environmental goals. For example, to maintain the portfolio value, any proposal should ensure or, at a minimum, maximize, the underlying long-term value and portfolio content category ("PCC") 1 status of RPS resources. Additionally, to support state policy, any proposal should be consistent with the intent of the California Energy Commission's PCL and not result in under-reporting of natural gas emissions.

//

//

//

IX. CONCLUSION

PG&E respectfully requests that these informal comments inform the Commission's consideration of the allocation and market offer mechanism proposal.

Respectfully Submitted,

By: /s/ M. Grady Mathai-Jackson
M. GRADY MATHAI-JACKSON

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 973-5520
E-Mail: grady.mathai-jackson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 30, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF PROTECT OUR COMMUNITIES FOUNDATION ON THE WORKING GROUP 3 CO-CHAIRS' ALLOCATION AND AUCTION PROPOSALS

Tyson Siegele
Energy Analyst
PROTECT OUR COMMUNITIES FOUNDATION
tyson@protectourcommunities.org

Ellison Folk
Yochanan Zakai
SHUTE, MIHALY & WEINBERGER LLP
folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: October 25, 2019

TABLE OF CONTENTS

Page

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF PROTECT OUR COMMUNITIES FOUNDATION ON THE WORKING GROUP 3 CO-CHAIRS' ALLOCATION AND AUCTION PROPOSALS

I. Introduction

On October 17, 2019, the co-chairs of Working Group 3 convened a workshop at which they presented the results of their discussions and deliberations to date. Protect Our Communities Foundation ("POC") participated in the October 17, 2019 workshop and provides the following informal comments pursuant to the schedule set by the co-chairs.

POC supports the continued inclusion of the Market Price Benchmark in the PCIA rate. The current Market Price Benchmark appropriately places a value on resources that are designated for sale to the market. It was developed and vetted in a lengthy process. POC strongly opposes the proposal by Southern California Edison ("SCE") and Commercial Energy to remove the Market Price Benchmark from the PCIA.

Next, POC supports the exclusive use of slice of generation contracts in the auction of Renewable Portfolio Standard ("RPS") attributes. When investor-owned utilities ("IOUs") have discretion in the contracting of Power Charge Indifference Adjustment-eligible ("PCIA") resources belonging to unbundled customers, controversy inevitably results. The co-chairs should avoid such controversy by requiring the exclusive use of slice of generation contracts.

POC opposes implementing a cap on long-term RPS sales because a cap would limit auction revenues and maximizing the value of those revenues is important.

POC supports the allocation and auction of every type of resource attribute. The co-chairs' proposal should include an auction for local resource adequacy ("Local RA") and greenhouse gas-free attributes.

II. The Co-Chairs Should Not Remove the Market Price Benchmark from the PCIA.

POC supports a rate structure that retains the Market Price Benchmark. Option 1, which would remove the Market Price Benchmark from the forecast that sets the PCIA rate is untenable for departing load customers. Removing the credit that represents the value of PCIA-eligible resources will result in a substantially higher and inequitable PCIA rate. POC supports fairly valuing PCIA resources before any sales are made and option 2 appears to meet POC's objective.

Option 1 violates the guiding principle of this docket: customer indifference. Option 1 would require the rates of an unbundled customer whose Load Serving Entity ("LSE") declines its allocation of PCIA-eligible resources to include the full cost of both resources declined by its LSE and resources acquired by its LSE. The fact that the LSE receives a credit for the value of auction revenues later in the year does not alleviate the need for its rates to cover the cost of the resources acquired before the credit arrives. Unbundled customers should not be required to bear the cost of attributes that their LSE declines *at any time*.[1]

Further, option 1 unreasonably transfers the burden of administration of PCIA bill credits from the IOUs to other LSEs. Today, the IOUs are responsible for calculating the cost of PCIA-eligible resources, forecasting the sale of attributes from PCIA-eligible resources, and calculating a vintaged PCIA rate based on that forecast in the ERRA proceeding. IOUs then track the revenue collected from unbundled customers by vintage, make sales of attributes from PCIA-

[1] Unless the attributes fail to sell at auction.

eligible resources, and track the revenues from those sales by vintage. Finally, the IOUs calculate the difference between revenues and costs in its PABA proceeding and collet net PCIA costs from customers. Option 1 provides revenues from sales to LSEs instead of applying the revenues as a credit to the customer's PCIA rate. In this way, option 1 transfers the administrative burden of tracking each customer's vintage and PCIA bill credit to LSEs that have not built the infrastructure necessary to perform such calculations, and may not have the information necessary to perform the calculations. For these reasons, option 1 is unreasonable, inequitable, and impractical.

The co-chairs presented an additional alternative where the Market Price Benchmark is set at the auction clearing price. The current Market Price Benchmark includes all available transactions in the previous year. POC does not support using the auction price as the Market Price Benchmark because its sample size is too small to comprise a reasonable estimate of the ongoing value of PCIA-eligible resources. POC recommends instead that the forecasted Market Price Benchmark continue to be set using all available transactions in the previous year. Actual auction revenues should be used as the final credit in the true-up.

III. POC Supports the Use of Slice of RPS Generation Contracts.

The co-chairs proposed that bidders may use either firm quantity, contingent, or slice of generation contracts in the auction of declined RPS. POC believes that these auctions should accept bids exclusively on slice of generation contracts. The use of firm quantity contracts is not appropriate because it would necessarily rely on the IOUs' discretion to select a mix of firm and non-firm contracts. In this working group's experience, when IOUs are provided discretion in the sale of PCIA-eligible resources belonging to unbundled customers, controversy inevitably results. For example, Peninsula Clean Energy sought to purchase Local RA for the 2019 reliability year. Peninsula Clean Energy responded to all of PG&E's requests for offers and made other efforts to procure capacity, but was unable to procure enough local RA to meet its need.[2] PG&E used its discretion to offer the needed capacity to the market only after the compliance deadline for LSEs to obtain RA for 2019.[3] In an effort to avoid a similar controversy surrounding the sale of RPS, and to restrict the IOUs' discretion in administering sales from resources belonging to unbundled customers, the co-chairs should require all RPS sales to use slice of generation contracts.

IV. A Cap on Long-Term RPS Sales Is Unnecessary.

POC disagrees with the co-chairs' proposal to cap the quantity of long-term sales made in the RPS auction. To capture the most value for the RPS product, IOUs should always accept the highest price offered for the sale of RPS regardless of contract length. A large quantity of renewable resources will enter the market as California moves towards its statewide renewable energy goals and more CCAs with aggressive renewable energy mandates form. With this influx of new renewable resources—built with the advantage of today's prices that are generally lower than the cost of the RPS resources in the PCIA portfolio—the market price of RPS products is likely to drop precipitously in the next several years. Therefore, the PCIA auction mechanism should capture the highest value of RPS products available in the near term. POC believes that the ability to secure long-term revenues for RPS resources in the near term is more important than ensuring that allocations from the PCIA portfolio are available to customers who switch between LSE providers.

V. Portfolio Optimization Mechanisms Should Promote the Sale of Entire Resources and Every Type of Resource Attribute.

Portfolio optimization mechanisms should promote the sale of PCIA-eligible resources in

[2] Notice of Ex Parte Meeting of the California Community Choice Assn., at p. 2 (May 13, 2019).
[3] *Id*.

a manner that ensures the greatest value for customers. First, IOUs should prioritize the sale of entire resources, which would create value for customers who would otherwise pay the full cost of those resources through the PCIA. Portfolio optimization mechanisms should also capture the full value of all a resource's attributes. Accordingly, long-term portfolio optimization mechanisms should allow for the sale of entire resources and buyout of power purchase contracts; short-term portfolio optimization mechanisms should allow for the sale of every type of resource attribute.

At the workshops, SCE stated that it does not want to be involved in transacting Local RA or greenhouse gas-free nuclear and hydro ("GHG-free") attributes. However, Commission directives control policy, not IOU preference. The IOUs are obligated to manage their portfolios prudently, which includes taking affirmative actions to transact PCIA-eligible resources in a way that creates the most value for all customers. It is imprudent for an IOU to withhold value from customers simply because an IOU prefers not to transact.

The following two sections describe issues still pending from POC's August 9, 2019 comments regarding Local RA and GHG-free auctions that remain relevant for the co-chairs' consideration today.

A. POC Supports the Co-chairs' Local RA Allocation Proposal When Paired With an Auction.

The co-chairs offer a proposal that allocates local RA to LSEs. POC supports the premise of this proposal as a short-term portfolio optimization mechanism if it is paired with an auction. Below, POC proposes a change to the local RA proposal's treatment of penalties.

First, POC disagrees with the co-chairs proposal that

> "any CAISO . . . penalties required for, or imposed as a result of, local RA resource outages will receive full cost-recovery through the PCIA . . . except for

> any costs disallowed through the IOU's [Energy Resource Recovery Account ("ERRA")] proceeding."[4]

Penalties should not automatically be eligible for recovery in the PCIA. IOUs maintain a responsibility to prudently manage their PCIA-eligible resources to avoid any penalties. Therefore, it is unreasonable to presume that these penalties are customers' responsibility. Instead, shareholders should take financial responsibility for any penalties, as they are responsible for managing their PCIA-eligible resources in a way that avoids the imposition of penalties.[5] Should shareholders seek to impose the cost of penalties on departing load customers, an IOU should be required to file an application, in a docket distinct from the ERRA proceeding, showing why these costs should be customers' responsibility. Put simply, penalties that result from imprudent management of resources should be shareholders' responsibility.

Second, the proposal allows the trading of allocated local RA attributes, but it does not define trading.[6] In response to a question from POC at the July 25, 2019 meeting, the co-chairs stated that trading includes sales. The revised proposal presented at the October 17, 2019 workshop continues to omit a definition of trading. The co-chairs' proposal should define the term trading to include sales.

B. POC Supports the Co-chairs' GHG-free Allocation Proposal When Paired With an Auction.

The co-chairs offer a proposal that allocates a proportional share of GHG-free attributes to other LSEs.[7] This proposal makes sense because GHG-free attributes have a value, and all

---

[4] July 25, 2019 Presentation at 25.

[5] If IOUs cannot manage their resources without incurring penalties, or do not want the obligation of resource management, they should sell those resources.

[6] July 25, 2019 Presentation, at 24.

[7] July 25, 2019 Presentation at 26-30.

customers who pay the PCIA are entitled to a portion of that value.[8] POC supports the premise of this proposal as a short-term portfolio optimization solution if it is paired with an auction. POC also suggests two clarifications to improve the co-chairs' GHG-free proposal.

GHG-free resources include nuclear and hydroelectric resources. Some Community Choice Aggregators ("CCAs") are not authorized to purchase or use nuclear resources, therefore any GHG-free allocation proposal should include a mechanism allowing LSEs to opt out of receiving GHG-free attributes from nuclear resources. The co-chairs disagree on what to do with the declined GHG-free attributes from nuclear resources. Commercial Energy would auction the declined attributes and credit the auction proceeds to the LSEs declining the attributes.[9] CalCCA and SCE would similarly allow LSEs to decline receiving GHG-free attributes from nuclear resources, but instead of auctioning off the declined attributes, they "would be reallocated automatically amongst LSEs participating in the allocation."[10]

POC supports Commercial Energy's proposal because it provides the LSE declining an allocation of GHG-free attributes the financial value of the attributes to which it was entitled. In contrast, CalCCA and SCE would allocate the value of attributes paid for by one LSE to the customers of another LSE without compensation. CalCCA and SCE offer no support for their proposal to allocate the value of attributes from one LSE to another without compensation. This aspect of the proposal offered by CalCCA and SCE should be rejected because it is unjust, unreasonable, and unfair that a customer who paid for a resource would not receive the value of

[8] *See* July 25, 2019 Presentation at 27 (a "credit within [the] Power Content Label, Clean Net Short, or other similar reporting mechanisms").

[9] *See* July 25, 2019 Presentation at 28; *Id*. at 33.

[10] July 25, 2019 Presentation at 28

the resource.

Finally, as noted with proposal regarding the sale of RA attributes, the co-chairs' proposal allows the trading of allocated GHG-free attributes but does not define the term trading.[11] The co-chairs' proposal should define the term trading to include sales.

VI. Conclusion

POC thanks the co-chairs for the opportunity to submit these comments and looks forward to participating in the Working Group process in the future.

DATED: October 25, 2019

SHUTE, MIHALY & WEINBERGER LLP

By: /s/ Yochanan Zakai

ELLISON FOLK
YOCHANAN ZAKAI*
396 Hayes Street
San Francisco, California 94102
(415) 552-7272
folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: October 25, 2019

PROTECT OUR COMMUNITIES FOUNDATION

By: /s/ Tyson Siegele

TYSON SIEGELE
Energy Analyst
4452 Park Blvd., #202
San Diego, California 92116
(917) 771-2222
tyson@protectourcommunities.org

---

[11] July 25, 2019 Presentation, at 28.

* Mr. Zakai is a member of the Oregon State Bar; he is not a member of the State Bar of California.

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

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

INFORMAL COMMENTS OF CITY OF SAN JOSE (SAN JOSE CLEAN ENERGY) ON WORKING GROUP 3's PHASE 2, WORKSHOP # 3 REGARDING PORTFOLIO OPTIMIZATION AND ALLOCATION AND AUCTION

RICHARD DOYLE
City Attorney

LUISA F. ELKINS
Senior Deputy City Attorney
Office of the City Attorney
200 East Santa Clara Street, 16th Floor
San José, CA 95113-1905
Tele: (408) 535-1953
Email: luisa.elkins@sanjoseca.gov

Attorneys for the City of San José, administrator of San José Clean Energy

October 28, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF CITY OF SAN JOSE (SAN JOSE CLEAN ENERGY) ON WORKING GROUP 3's PHASE 2, WORKSHOP # 3 REGARDING PORTFOLIO OPTIMIZATION AND ALLOCATION AND AUCTION

The City of San José ("San José"), on behalf of San José Clean Energy ("SJCE"), respectfully submits the following informal comments on the October 17, 2019 Phase 2, Workshop #3, hosted by the Working Group 3 ("WG3") regarding Portfolio Optimization and Allocation and Auction ("Workshop #3"). SJCE appreciates the opportunity to provide these comments and supports all efforts from stakeholders and the California Public Utilities Commission ("Commission") to improve the resource adequacy ("RA") market.

I. DISCUSSION

A. Timing for RA Allocation and Auction

At Workshop #3, WG3 presented a timeline for the voluntary allocation and market sale of system and flexible RA that would fit within the current Commission RA schedule. Under this timeline, the open enrollment period for allocations would occur during mid-August, with market offer of unallocated RA products occurring around mid-September or early October. At the workshop, the CalCCA co-lead stated that WG3 may consider proposing a revised Commission timeline as part of this working group to allow load serving entities ("LSEs") sufficient time to procure RA prior to the October 31st compliance deadline. SJCE emphasizes that it is extremely important that the timeline be shifted up. Market offer of unallocated RA products should occur prior to the end of April, and the Commission timeline must be adjusted accordingly. An end-of-April allocation and auction would ensure that unallocated products are available on the market for six months prior to the compliance deadline for orderly procurement of resources, in contrast to the mere weeks that are suggested under the current timeline.

B. Long-Term Allocations and Sales

During Workshop #3, the CalCCA co-lead indicated that WG3 is not currently considering longer-term (e.g., more than a year) allocations and sales for system and flexible RA, and that one-year allocations are preferred because they give LSEs the most flexibility to respond to Commission RA rule changes, which often occur from year to year. While SJCE agrees that it is certainly beneficial to have options for one-year allocations and sales for maximum flexibility, opportunities for LSEs to access multi-year system and flexible RA are also necessary to enhance market stability. SJCE is assessing several long-term contracts for RA, and it is very likely that other LSEs are doing so as well. If LSEs begin fulfilling a significant portion of their RA obligation with long-term contracts, the interest in one-year contracts or allocations would eventually be low. SJCE recommends that long-term options for RA are included as part of the WG3 proposal to increase options for LSEs.

Regarding long-term allocations and sales for Renewable Portfolio Standard ("RPS") credits, SJCE agrees with CalCCA that allocations and sales must be for 10+ year terms to qualify as long-term RPS under statutory requirements.

C. Ratemaking Proposals

Two ratemaking proposals were presented during Workshop #3. Of the two proposals, SJCE supports CalCCA's ratemaking proposal and strongly opposes the ratemaking option presented by Southern California Edison (WG3 co-lead) and Commercial Energy. Customers would see a much higher Power Charge Indifference Adjustment ("PCIA") than they do today under this latter proposal because all the costs of the resource go into the PCIA. As acknowledged at Workshop #3, the ratemaking methodology proposed by these parties would make it very challenging for Community Choice Aggregators to index their rates based on investor-owned utility rates due to the mismatch between the timing of the PCIA payment and the auction from which revenues are received.

Respectfully submitted by:

RICHARD DOYLE
City Attorney

/s/ Luisa F. Elkins

LUISA F. ELKINS
Senior Deputy City Attorney
Office of the City Attorney
200 East Santa Clara Street, 16th Floor
San José, CA 95113-1905
Tele: (408) 535-1953
Email: luisa.elkins@sanjoséca.gov

Attorneys for the City of San José,
administrator of San José Clean Energy

Dated: October 28, 2019

November 8, 2019

INFORMAL COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY REGARDING PCIA WORKING GROUP 3 THIRD WORKSHOP (R.17-06-026)

SDG&E appreciates the opportunity to provide these comments regarding the co-chairs' Working Group 3 proposal. In Decision (D.) 18-10-019, the Commission ordered initiation of Phase 2 of the proceeding to "consider the development and implementation of a comprehensive solution to the issue of ***excess resources*** in utility portfolios. We expect that solution to be based on a voluntary, market-based redistribution of excess resources in the electric supply portfolios of [the Investor Owned Utilities ("IOUs")]."[1] The Phase 2 Scoping Memo directed parties to address four topics. The three workshops held to date by Working Group 3 have focused on answering the first of these four issue areas:

> What are the structure, processes, and rules governing portfolio optimization that the Commission should consider in order to address excess resources in utility portfolios? How should these processes and rules be structured so as to be compatible with the Commission's ongoing Integrated Resource Planning and [Resource Adequacy ("RA")] program modifications in other proceedings?

The issues tackled by Working Group 3 are among the most difficult and contentious of the proceeding. Developing the framework envisioned by the Commission is no easy task, and SDG&E appreciates the significant time and effort the co-chairs have devoted to the exercise. While the co-chairs have made substantial progress, the allocation proposal does not fully meet the directive set forth in the Phase 2 Scoping Memo, with a major impediment being the current impasse regarding the definition and quantity of buffer and uncertainty. SDG&E urges the co-chairs to reengage with this effort, and offers the following observations to help pinpoint areas of future focus:

First, the allocation proposal only partially deals with the utilities' excess resources. In a scenario where the IOU has no excess resources above the bundled customers' needs, the mandatory allocation methodology would distribute RA attributes and renewable energy credits ("RECs") to the community choice aggregators ("CCAs") that gained the departed customers based on their forecasted load share. This, in turn, creates additional costs to bundled customers since the IOU must procure additional products in the bilateral market to meet its customers'

---

[1] D.18-10-019, p. 4 (emphasis added).

needs to the extent that the IOU is short after the allocation process. On the other hand, if the IOU has excess resources even after the allocation process, it would signify that the allocation methodology did not distribute the entirety of the excess resources to departed load and the IOU would still have excess resources that it may or may not elect to sell in the bilateral market. In either case, the allocation proposal does not answer the question of how the IOU must optimize excess portfolio.

Second, the allocation proposal potentially limits the IOUs' ability to optimize its portfolio in the future because the long-term allocations are binding. This would limit any sale of the resource to a buyer because the buyer may not wish to be obligated to continue to allocate products in the long-term. The IOUs must have the flexibility to "right-size" their portfolios and meet the directive in the Phase 1 decision to reduce overall costs for customers as load departure occurs. The binding allocation does not offer this flexibility and effectively requires the IOUs to keep resources on its balance sheet in the long-run that it no longer needs to serve its load.

Third, SDG&E does not support the proposal to allow load-serving entities ("LSEs") to trade allocations rather than actual RA capacity with other LSEs. This proposal creates a new product that is a derivative of the current RA capacity product construct. SDG&E does not believe a new RA product should be developed in order to facilitate the allocation methodology and potentially increase the complexity of the tracking mechanism under the current RA framework. SDG&E prefers that LSEs continue to transact based on the current net qualifying capacity ("NQC") RA product that is prevalent in the current bilateral market construct.

Fourth, SDG&E cannot support a construct that shifts long-term RPS portfolio risks to its bundled customers. SDG&E fears that allocating firm products from the IOU portfolio for future delivery periods (*e.g.*, long-term allocations) could impose unnecessary risks to bundled customers given the fluctuating nature of portfolio deliveries. Also, considering imminent load departure, SDG&E endeavors to "right-size" its portfolio and submits that long-term allocations inhibit its ability to meet the Commission's directive to do so. SDG&E requests that in the next workshop, the co-leads discuss contract assignment/novation, buy-outs and other available optimization tools as a means to address LSEs' requests for long-term resources and SDG&E's desire to "right-size" its portfolio.

Finally, all portfolio optimization paradigms – including allocation – must ensure fair treatment. This means that *every* attribute of a resource type, including the brown power component, must be subject to allocation. This is fundamental to establishing an equitable allocation process. Allowing non-IOU LSEs to receive allocations from only greenhouse gas ("GHG")-free resources would mean that only IOU portfolios would include energy from GHG emitting resources – even though this energy was procured to serve the customers that later departed utility service. In an allocation construct, IOUs should be permitted to allocate to departed load their fair share of *all* PCIA portfolio eligible attributes, including the energy from GHG emitting resources along with the GHG-free resources.

***

BEFORE THE PUBLIC UTILITIES COMMISSION OF
THE STATE OF CALIFORNIA

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

COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 2 WORKING GROUP #3 WORKSHOP #3

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Matthew Freedman, Staff Attorney
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org
October 28, 2019

COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 2 WORKING GROUP #3 WORKSHOP #3

TURN offers the following comments on certain issues reviewed in the 3rd workshop of Working Group 3 (WG 3), regarding portfolio optimization and cost reduction, and allocation and auction. Citations refer to slides presented at the 3rd workshop (Presentation).

Allocations of long-term contract compliance attributes

Stakeholders disagree about the required elements of the proposed voluntary allocation structure that would allow LSEs to use IOU contracted RPS eligible resources to satisfy the long-term contract compliance obligations established under Public Utilities Code §399.13(b). While CalCCA argues for a minimum allocation term of at least 10 years, SCE and Commercial Energy propose no minimum allocation term.[1]

CalCCA is correct. In order for an LSE to demonstrate compliance with the long-term contracting requirement, it must enter into a binding and specific commitment that extends into the future for a duration of at least 10 years. In D.17-06-026, the Commission affirmed that any "repackaging" of a long-term contract must remain consistent with the approach adopted in D.12-06-038.[2] Each retail seller must demonstrate that it has made a long-term commitment (via ownership or contract) for output from RPS-eligible facilities. Under no circumstances does "repackaging" permit any long-term contract or ownership agreement to retain its compliance value under §399.13(b) if it is resold or allocated for a term of less than 10 years. The language of §399.13(b) expressly requires that the retail seller must procure sufficient quantities from "its contracts of 10 years or more in duration" to satisfy the obligation.

There is no basis to allow any short-term procurement allocation to a retail seller to satisfy the requirements of §399.13(b) even if there is a demonstration that the

[1] Presentation, page 14.
[2] D.17-06-026, pages 21-22.

underlying contract executed by the IOU with the RPS-eligible facility involves a long-term commitment. In D.12-06-038, the Commission rejected requests by several parties to permit "slicing and dicing" of eligible long-term contracts into short-term resale contracts that retain a "long-term" attribute.[3] In D.18-05-026, the Commission reaffirmed this treatment in rejecting a petition by Shell to allow the requirements of §399.13(b) to be satisfied when a long-term contract is repackaged with portions resold to a subsequent buyer making a commitment of less than 10 years.[4]

Given the clear statutory language and a line of unambiguous Commission decisions interpreting the nature of the requirements, there is no basis for WG3 to propose an approach to allocation that seeks to transfer "long-term contract attributes" without an offtake commitment of less than 10 years in duration. TURN strongly urges the WG3 co-leads to conform any final proposal to these requirements.

Any voluntary allocation of RPS or GHG-free resources must be structured as a forward sale of a bundled product

The proposed voluntary allocation of RPS and GHG-free resources would allow LSEs to accept an assignment of a share of the IOU portfolio. Without taking a position on the two ratemaking options outlined in the presentation, TURN believes that the WG3 proposal must take great care to conform to existing conventions relating to the forward sale of bundled products.

It is not entirely clear from the presentation whether the structure for allocating both RPS and GHG-free resources is consistent with the approach currently used by IOUs for selling these products on a forward basis. TURN would be particularly concerned about any initiative to create a new class of unbundled GHG-free attributes that can be traded

[3] In R.11-05-005, both Noble and PG&E requested changes to the long-term contract obligations that would have permitted short-term contracts to substitute for long-term contracts required under the RPS obligations. The Commission declined to adopt this treatment in D.12-06-038.
[4] D.18-05-026, pages 25-27.

separately from the electricity generated by the associated units. Any such scheme would run afoul of both the Clean System Power methodology used in the Integrated Resource Planning (IRP) process and the California Energy Commission's Power Source Disclosure Program (PSDP). Neither program allows LSEs to acquire unbundled attributes that can be used to offset portfolio GHG emissions for reporting purposes.

So long as all allocated products are conveyed on a forward basis and include attributes bundled with the associated electricity from the underlying generator, the proposals under consideration by WG3 should not conflict with the IRP and PSDP protocols. TURN would appreciate clarifications with respect to this issue as part of any final working group report submitted to the Commission.

TURN appreciates the opportunity to submit these comments.

Respectfully submitted,

MATTHEW FREEDMAN

__________/S/___________

Matthew Freedman
Staff Attorney
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org

Dated: October 28, 2019

Appendix C

INFORMAL COMMENTS ON ISSUES 2 TO 4

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

PROTECT OUR COMMUNITIES FOUNDATION'S PROPOSALS FOR PORTFOLIO OPTIMIZATION

Tyson Siegele
Energy Analyst
Protect Our Communities Foundation
tyson@protectourcommunities.org

Ellison Folk
Yochanan Zakai
SHUTE, MIHALY & WEINBERGER LLP
Folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: November 4, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

PROTECT OUR COMMUNITIES FOUNDATION'S PROPOSALS FOR PORTFOLIO OPTIMIZATION

I. INTRODUCTION

On October 17, 2019, the co-chairs of Working Group 3 convened a workshop at which they requested that parties submit proposals via informal comments to the service list by November 4, 2019. Protect Our Communities Foundation ("POC") submits these comments pursuant the schedule set by the co-chairs.

POC requests that its proposals be discussed at one or more of the co-chairs' weekly meetings, and that the co-chairs invite POC to participate fully in the discussion of its proposals.

In these comments, POC recommends that the working group consider mechanisms designed to remove resources from investor-owned utilities' ("IOUs'") portfolios. The best mechanism to facilitate the removal of resources from the IOUs' portfolios is a sunset of the Power Charge Indifference Adjustment ("PCIA"). POC proposes that the PCIA sunset five years following a customer's departure from bundled service. Under POC's sunset proposal, IOUs are responsible for managing their portfolios such that the portfolio contains no excess resources five years following a customer's departure from bundled service. If an IOU's portfolio of PCIA-eligible resources is so mismanaged that 23 years after the legislature enacted AB 117 it still includes excess resources, then that IOU's shareholders should be responsible for the cost of those resources.

Next, any portfolio optimization mechanisms proposed by the co-chairs should facilitate the transfer of a large quantity of resources because an IOU may need to transfer a large quantities of resources from its portfolio.

Finally, POC believes that all of working group 3's proposals should include automatic enforcement and shareholder responsibility mechanisms. Accordingly, we present specific proposals for automatic enforcement of the co-chairs' allocation and auction proposal.

II. The Working Group Should Consider Mechanisms Designed To Remove Resources From IOU Portfolios.

IOUs should prioritize the sale of entire resources, which would create the most value for customers who are responsible for paying the full cost of those resources through the PCIA. Long-term portfolio optimization mechanisms should allow for the sale of entire resources and the buyout of power purchase contracts for which an IOU has no long-term need. Since submitting our first set of comments to this working group six months ago, POC has asked for the working group to consider the removal of entire resources from IOUs' portfolios. As the Alliance for Retail Energy Markets noted in their most recent comments, this is the most important issue that the working group was charged to resolve,[1] and one that the working group should have prioritized addressing from day one. While we are disappointed that the co-chairs have not responded to our previous comments on this issue, we look forward to working on this topic with the co-chairs moving forward.

POC is concerned about the ability of the working group to develop an effective proposal in the time available before the working group's final report is due on January 30, 2020. If the co-chairs are not able to develop a proposal that results in IOUs divesting entire resources, they

[1] Alliance For Retail Energy Markets Informal Comments On PCIA Working Group 3 Meeting #3, at pp. 1-2 (October 28, 2019).

should submit their allocation and auction proposal for Commission consideration and request additional time for the working group to develop an effective proposal to address this critical issue.

The allocation and auction proposal provides a way to transfer specific resource attributes from IOUs to other load serving entities ("LSEs") on an annual basis. Such a short-term transfer of attributes does not obviate the need for IOUs to divest from their portfolios those resources that they do not need in the long-term. As we noted in earlier comments, POC's support of any short-term transfer of individual attributes is coupled with its strong desire to see a long-term portfolio optimization mechanism that removes resources from the IOUs' portfolios. The best mechanism to facilitate the removal of resources from the IOUs' portfolios is a sunset of the PCIA.

A. The PCIA Should Sunset In Five Years.

After five years, no unbundled customers should be responsible for paying for the costs of IOU-controlled resources. In 2002 the legislature enacted AB 117 directing the Commission to create a short-term solution to account for resources procured on behalf of customers that switch to a community choice aggregation program ("CCA"). AB 117 specifically instructed that the PCIA be for a limited period of time.[2] The legislature did not describe the PCIA as a long-term solution because an IOU would eventually downsize its portfolio to eliminate the need to charge departed customers for excess resources. IOUs have been on notice for seventeen years that their portfolios must be managed to remove excess resources following the creation of a CCA.

[2] Pub. Utils. Code § 366.2(f)(2).

IOUs should be assigned the responsibility to downsize their portfolios by a date certain. If IOUs are provided a deadline by which to have a right sized portfolio, IOUs will take appropriate actions before that deadline. These actions could include letting existing contracts expire, taking decisive positions against additional and unneeded procurement requirements, contract buyouts, and selling owned generation. Setting a long-term goal for IOUs to right size their portfolios has the added benefit of not requiring the Commission or stakeholders to micromanage the IOUs' portfolio management activities. In order for the Commission and stakeholders to be confident that the IOUs will meet the goal set by the Commission, the deadline should be mandatory and include financial consequences for shareholders as described below.

POC proposes that the PCIA sunset in five years. While IOUs may administer contracts for resources that are longer than five years in length, utilities have ongoing opportunities to renegotiate contract terms and propose the buyout or transfer of contracts to other LSEs. Similarly, the fact that an IOU owns a resource does not mean that CCA customers should be responsible for paying for a utility-owned resource in perpetuity. Instead, IOUs should sell unneeded resources.

For example, if POC's proposal is adopted in 2020, then IOUs must manage their portfolios to eliminate excess resources and PCIA costs for all customers that departed bundled service in 2020 or earlier by 2025. At that point, the IOUs would have had 23 years after the legislature enacted AB 117 to prepare for the phase out of PCIA fees. If an IOU's portfolio of PCIA-eligible resources is so mismanaged that 23 years after the legislature enacted AB 117 it still includes excess resources, then that IOU's shareholders should be responsible for the cost of those resources.

The five year sunset would also apply to CCAs formed after the proposal is adopted. For example, if a customer departs bundled service in 2021, then the IOU must manage its portfolio to eliminate excess resources and PCIA costs for that vintage by 2026. In this way, the PCIA would not be imposed on a vintage of customers for more than five years.

B. Portfolio optimization mechanisms should facilitate the transfer of a large quantity of resources.

In addition to sunsetting the PCIA, the co-chairs could consider other mechanisms to remove resources from IOUs' portfolios. If the co-chairs do so, any mechanism should include a structure designed to facilitate the transfer of a large quantity of resources because an IOU may need to eliminate large quantities of resources from its portfolio. For instance, San Diego Gas and Electric ("SDG&E") will need to divest a large quantity of resources. On September 17, 2019, the City of San Diego adopted an ordinance establishing a Community Choice Aggregation ("CCA") program and a resolution to execute a regional CCA Joint Powers Authority ("San Diego CCA"), with the cities of La Mesa, Chula Vista, Encinitas, and Imperial Beach.[3] The San Diego CCA is expected to serve more than 50 percent of SDG&E's load when it begins service in in 2021.[4] Therefore, in designing portfolio optimization mechanisms, the working group should ensure that any mechanism proposed can be used to efficiently divest a large portion of an IOU's resource portfolio. POC repeats its request that the co-chairs evaluate each proposal brought forward to address whether it is able to facilitate the transfer of a large quantity of resources and discuss this evaluation at future meetings.

---

[3] City of San Diego Informal Comments on Proposed Decision of ALJ Atamturk Refining the Method to Develop and True Up Market Price Benchmarks, at p. 1 (Sept. 26, 2019).
[4] *Id*.

III. All The Co-Chairs' Proposals Should Include Automatic Enforcement and Shareholder Responsibility Mechanisms.

The co-chairs' allocation and auction proposal, as well as any proposals to divest entire resources from IOUs' portfolios, should include automatic enforcement mechanisms to ensure IOUs immediately implement the portfolio optimization mechanisms adopted by the Commission. This section first discusses POC's proposed automatic enforcement and shareholder responsibility mechanism for the co-chairs' allocation proposal, and then discusses the same for co-chairs' auction proposal.

The co-chairs' annual PCIA allocation mechanism requires IOUs to regularly provide to other LSEs the quantity of their forecast and actual allocations of resources attributes. IOUs that do not provide these forecast and actual allocation amounts on a schedule approved by the Commission should provide bill credits to bundled and unbundled customers. These bill credits should be given by IOU shareholders to customers within 60 days of the missed deadline, without the need for any Commission action.

IOUs should administer the PCIA allocation mechanism in a timely, efficient, fair, and transparent manner because they control access to information about the PCIA resources paid for by all customers. POC's automatic enforcement and shareholder responsibility mechanism aligns the interest of shareholders in avoiding penalties with the interests of all customers in an efficient and timely administration of the allocation mechanism. It also compensates customers when they are harmed by an IOU's mismanagement of the allocation mechanism.

For example, IOUs that publish final allocations that underallocate attributes to unbundled customers should provide credits to unbundled customers' bills. Similarly, IOUs that publish final allocations that underallocate resources to bundled load customers should provide automatic credits to bundled customers' bills. Based on the information provided by the co-chairs to date, it is unclear to POC exactly which allocation calculations are to be performed by the IOUs, and which by the Energy Division. POC requests that the co-chairs provide this clarity and work with POC design this automatic enforcement mechanism.

Next, the co-chairs' annual PCIA auction mechanism requires IOUs to regularly administer solicitations for bids on certain attributes from PCIA resources. The efficient administration of these solicitations is an essential part of the co-chairs' proposal to reduce the PCIA rate. Due to the IOUs' track record in administering PCIA resources, POC is concerned that IOUs may not efficiently and accurately administer these auctions. POC's proposal aligns shareholders' interest in avoiding penalties with customers' interest in efficient administration of these auctions.

POC proposes that if an IOU that does not complete its auction on the schedule set by the Commission, within 60 days of the missed deadline the IOU's shareholders should provide bill credits to the unbundled customers on whose behalf the action was to be conducted.

Further, POC proposes that an IOU withholding resources that an LSE requested be auctioned provide bill credits to the unbundled customers on whose behalf the auction was to be conducted. The credit would be in the amount of the highest auction bid, or most recent market price benchmark for that attribute, if no auction took place, multiped by the quantity of attributes not auctioned.

IV. CONCLUSION

POC thanks the co-chairs for the opportunity to submit these proposals, and requests that these proposals be discussed at one or more of the co-chair's private meetings, and that POC be invited to participate fully in the discussion of its proposals.

DATED: November 4, 2019

SHUTE, MIHALY & WEINBERGER LLP

By: /s/ Yochanan Zakai

ELLISON FOLK
YOCHANAN ZAKAI*
396 Hayes Street
San Francisco, California 94102
(415) 552-7272
Folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: November 4, 2019

PROTECT OUR COMMUNITIES FOUNDATION

By: /s/ Tyson Siegele

TYSON SIEGELE
Energy Analyst
Protect Our Communities Foundation
4452 Park Blvd., #202
San Diego, California 92116
(917) 771-2222
tyson@protectourcommunities.org

* Mr. Zakai is a member of the Oregon State Bar; he is not a member of the State Bar of California.

Appendix D

FOURTH WORKSHOP PRESENTATION

PCIA Phase 2 – Working Group Three

Portfolio Optimization and Cost Reduction, and Allocation and Auction

Refinement of Issue 1 Proposals; Issues 2-4

Workshop No. 4
December 11, 2019

Safety – Roles & Responsibilities

Call
911

Ann
Springgate

CPR
AED
First Aid

CPR: TBD
AED:
Sam Kang
First Aid:
Maria Litos

Meet & Greet
Safety
Personnel

Doug
Karpa

Duck
Cover &
Hold

Sweep the Room

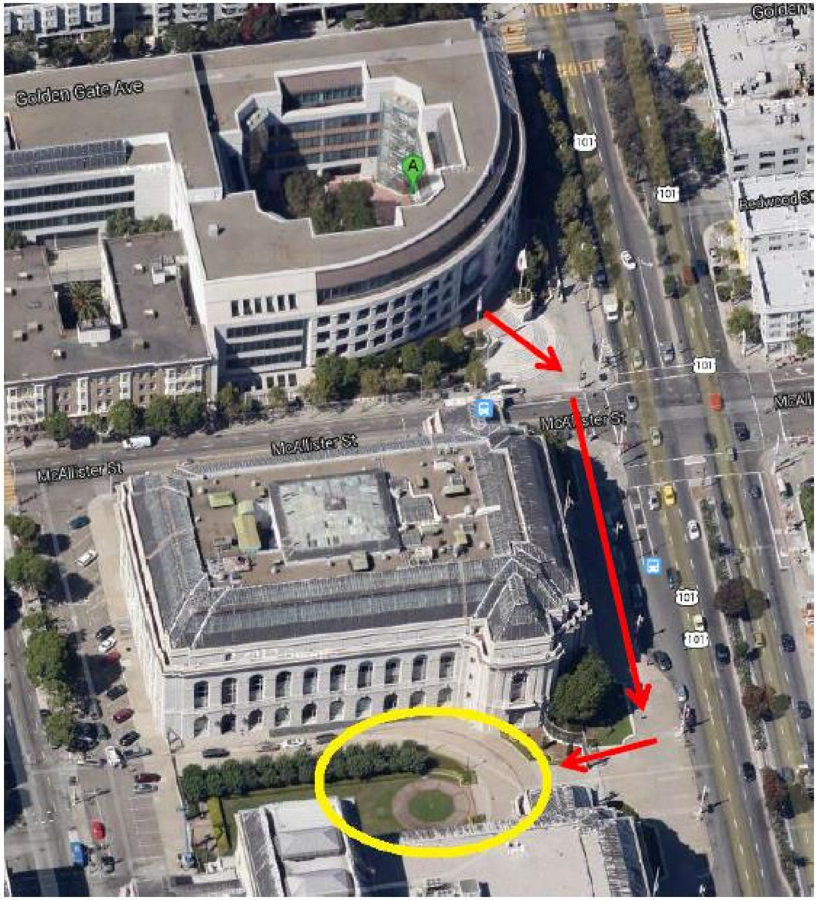
Shagun
Tougas

Silence Cell Phones
Get OUT
Hide OUT
Keep OUT
Take OUT

Safety – Evacuation Procedure

In the event of an emergency evacuation:

- Cross McAllister Street
- Gather in the Opera House courtyard down Van Ness, across from City Hall.



WiFi Access

Network: CPUCguest

Username: guest

Password: cpuc113019

Agenda

- Safety and Status Check
- Issue 1 - Recap and Refinement of Proposals
  - Resource Adequacy Updates
  - RPS and GHG-Free Energy Updates
  - Other Updates
- Issue 2 – Active Management of IOU Portfolios
- Issue 3 – Potential Adoption of Additional Standards for Active Portfolio Management and the Transition
- Issue 4 – New or Modified Shareholder Responsibility
- Next Steps

Working Group Three – Issues to be Discussed
Scoping Memo R.17-06-26

1. What are the *structures, processes, and rules governing portfolio optimization* that the Commission should consider to address excess resources in utility portfolios? How should these processes/rules be structured to be compatible with the ongoing IRP and RA program modifications in other proceedings?

2. What standards should the Commission adopt for *more active management of the utilities' portfolios in response to departing load* in the future to minimize further accumulation of uneconomic costs?

3. If the Commission were to adopt standards for more active management of the utility portfolios, *how should the transition to new standards occur* (e.g., timeframe, process, etc.)?

4. Should the Commission *consider new or modified shareholder responsibility for future portfolio mismanagement*, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards? Are ERRA or GRC proceedings the appropriate forums to address prudent management of portfolios?

Recap and Refinement of Issue 1 Proposals

PCIA Phase 2 - Working Group 3

Recap: Allocation & Market Offer Process & Products

- The Co-Leads presented four proposals at the previous WG3 Workshop

	Local RA	GHG-Free	RPS	System / Flex RA
Pro rata vintage share	Peak-Load	Forecasted Annual Load Share	Forecasted Annual Load Share	Peak-Load
Allocation	Mandatory	Voluntary (all or portion)	Voluntary (all or portion)	Voluntary (all or portion)
Market Offer	N/A	N/A	Long-term and short-term bundled RPS	Monthly or Annual

Recap: Local RA and GHG-Free Energy Proposals

- Local RA Allocation Proposal
  - Mandatory allocation via a CAM-like mechanism, but may be traded*,**
    - Commercial supports voluntary allocation with auction of unallocated RA
  - Multi-year forward allocations track Local RA obligations
  - System and Flex RA from Local resources follows Local RA allocation
  - Allocated products receive a benchmark value of $0 in PCIA mechanism
- Voluntary GHG-Free Energy Allocation Proposal
  - Voluntary option to accept all or none of Nuclear or Non-Nuclear pools of GHG-free energy
    - Unallocated energy is re-allocated amongst LSEs accepting allocation
    - Commercial Energy supports voluntary allocation of any portion of pools, with unallocated energy being auctioned off
  - IOU continues to serve as Scheduling Coordinator for energy
  - No change to PCIA rates, as GHG-free energy receives no additional benchmark value

* SCE is neutral to trading of Local RA after an allocation, but if permitted, does not believe IOUs should be required to manage the process

** CalCCA will not support any allocation scheme that does not allow trading of allocated products

Recap: Voluntary Allocation & Market Offer Proposal for RPS and System/Flex RA

- LSEs can make an annual election to accept or decline an allocation of their vintaged share of available PCIA-eligible RPS energy & System/Flex RA
- IOU will offer to the market the unallocated RPS energy and/or System/Flex RA
- IOU will continue to manage the PCIA portfolio, performing the following functions:
  - Schedule energy into the CAISO market;
  - Show RA through a CAM-like mechanism;
  - Transfer bundled RECs to benefiting LSEs; and
  - Provide information to certify RPS energy for Power Content Label
- IOU may continue to perform portfolio optimization activities outside of Voluntary Allocation and Market Offer mechanism

Updates to Prior RPS Proposal

PCIA Phase 2 - Working Group 3

Update to RPS & GHG-Free Allocation Structure

- Co-Leads propose to use forecasted, vintage, load shares for determining allocation percentage; quantities will be determined by actual generation

- Co-Leads previously proposed to allocate RPS and GHG-free energy on an actual, vintaged, annual load share basis
  - Concerns that load share uncertainty resulted in additional complexity, particularly for market offer process

Update to RPS Long-Term Attribute Preservation

- Stakeholder feedback supported the position that to preserve long-term attribute preservation, LSEs must accept allocations for 10+ years
- CalCCA and SCE propose that in order for an LSE to receive the “long-term” benefits from RPS allocation, they must elect to receive their allocation share through the life of their vintage*
  - LSEs that opt for short-term allocation will not receive long-term benefits
  - To receive long-term credit, the longest RPS contract in their vintage must have a remaining term of at least 10 years
    - Excluding UOG and evergreen contracts to extent they exist
  - Allocations count as long-term regardless of underlying contract terms if allocation is accepted at LSE’s first election opportunity
- LSEs taking allocations may be required to enter into Commission pre-approved contract/confirm
- Quantities available for allocation are subject to any IOU portfolio optimization

*Must commit to the longest term of any single contract in the vintage

Update to RPS Voluntary Market Offer Structure

- Annually, the IOU will offer to sell all unallocated RPS energy for a term beginning in the prompt year
  - Long-term sales will be offered up to a 35% cap applied to the lesser of LSE's (a) total allocation share or (b) sales election
    - RPS sales will convey long-term attributes only if sold for 10+ year terms
  - Long-term sales amounts will be based upon the LSE's forecasted minimum allocation for the term of the long-term offer
- The co-leads propose an annual report (new or existing) be published by Energy Division summarizing results of the auctions and potential impact of the cap on long-term sales on realized value
- Recommend a reassessment of the cap by CPUC after 2 years

Refinement of System/Flex RA Proposal

PCIA Phase 2 - Working Group 3

Proposal for Allocating System and Flexible RA

- RA allocation process
  - Resources by attributes pooled together for distribution similar to current CAM process
  - Distribution shown on the LSE Allocations tab of CPUC RA template
- Secondary Trading of RA allocations
  - LSEs can trade their RA allocations in a secondary market outside of VAMO
  - Trade amounts identified on the same LSE Allocations tab
  - Trade process is based on modifications to existing CPUC RA template
  - After initial allocation, no further IOU involvement is required
- Co-leads may consider further refinement

LSE Allocation Tab Example

Month	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
SP26 CAM Capacity	0	0	0	0	0	0	0	0	0	0	0	0
NP26 CAM Capacity	50	50	50	50	50	50	50	50	50	50	50	50
RA Allocation North System	12	12	12	12	12	12	12	12	12	12	12	12
RA Allocation South System												
RA Allocation LA Basin												
RA Allocation Big Creek-Ventura												
RA Allocation Sand Diego-IV												
RA Allocation Bay Area	11	11	11	11	11	11	11	11	11	11	11	11
RA Allocation Fresno	4	4	4	4	4	4	4	4	4	4	4	4
RA Allocation Sierra	3	3	3	3	3	3	3	3	3	3	3	3
RA Allocation Stockton	2	2	2	2	2	2	2	2	2	2	2	2
RA Allocation Kern	1	1	1	1	1	1	1	1	1	1	1	1
RA Allocation Humboldt	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
RA Allocation NCNB	2	2	2	2	2	2	2	2	2	2	2	2
RA Allocation Flex												
NP26 Condition 2 RMR	5	5	5	5	5	5	5	5	5	5	5	5
SCE Preferred LCR Credit	0	0	0	0	0	0	0	0	0	0	0	0

Then we can have a part II of Table 8 that shows a transfer to LSE and net any allocations. ↓

Net Monthly Position	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
RA Allocation Sierra example	4											
RA Allocation NCNB example	1											
RA Allocation Bay Area example	7											
RA Allocation Humboldt	1.5											
List each of the allocations												

Likely we can't unbundle Flex so we may need each of the RA Allocation categories to be with or sans Flex (just adding it here for simplicity of the illustration

Monthly Trades	Product	LSE	Volume
LCPSF	Sierra		1
CRLL	NCNB		-1
TPES	Bay Area		-4
CRLL	Humboldt		1

Example for January only

Other Issue 1 Refinements

Spring System / Flex RA Market Offer

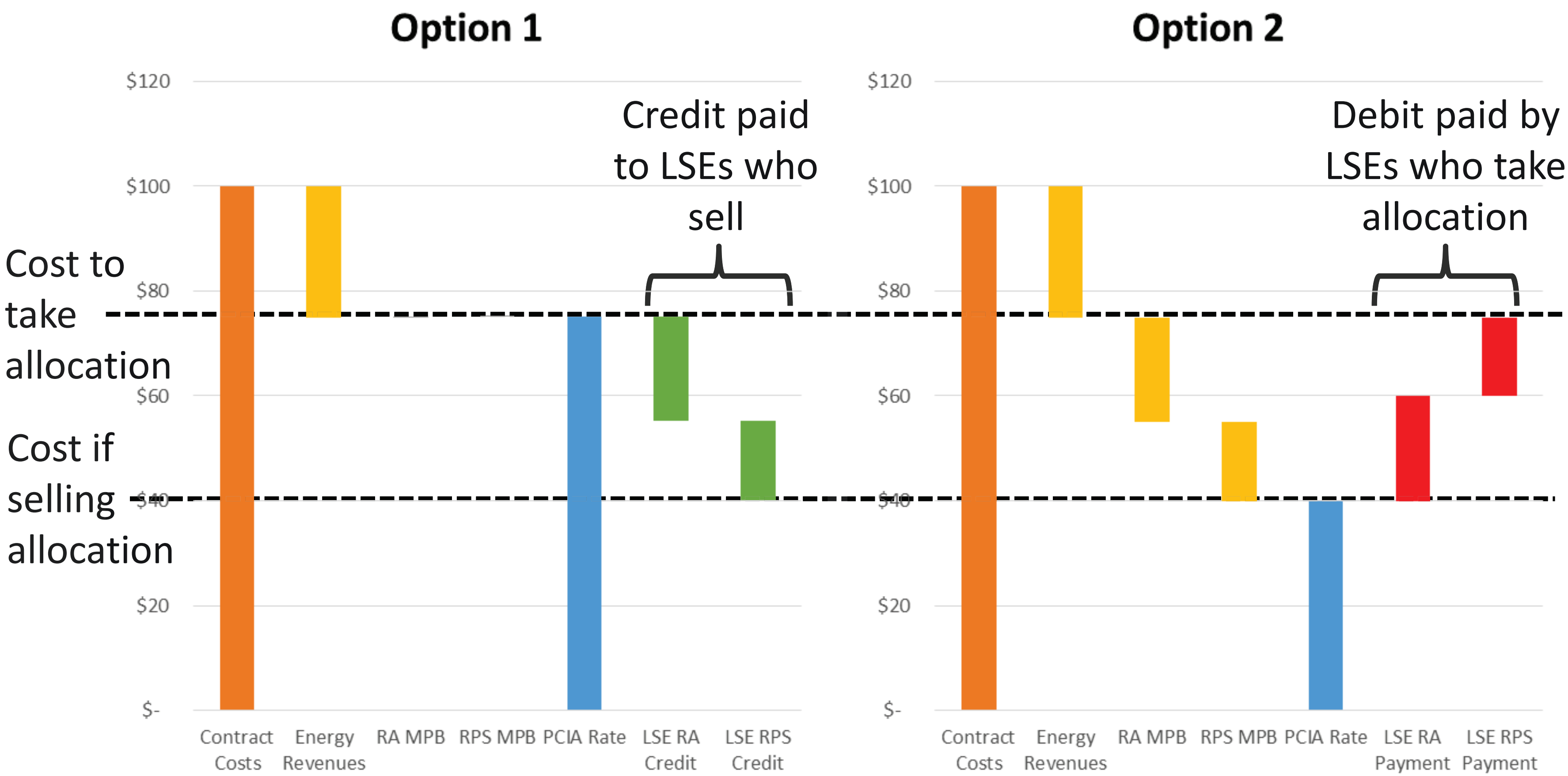
- Under the existing schedule for determining final LSE RA obligations, there is only a short window for procurement between receiving RA obligations and the year-ahead RA showing
- In order to relieve this pressure and maximize the RA value in the Market Offer process, the co-leads propose adding an additional System/Flex RA Market Offer in the spring of each year
- Volume available in the spring Market Offer would be determined as follows
  - LSE's would have an early opportunity to decline their allocation for the following year in Q1 (e.g., decline in Q1 2020 for allocation in 2021)
  - For any volumes declined for allocation in Q1, a percentage* of the declined allocation would be made available
  - LSE's who do not decline their allocation in Q1 will still be able to make their allocation decision in the fall
  - The fall Market Offer will include unsold volumes from the spring market offer and any unallocated RA based on fall allocation decisions

* Co-leads are considering 50%-75% depending on timing of early market offer

PCIA Ratemaking Structures - Recap

- Seek to minimize complexity of PCIA ratemaking and billing
- All customers in the same vintage pay the same PCIA rate
- Option 1:
  - All customers pay full resource costs, less CAISO revenues
  - Product types available for allocation receive $0 value
  - LSEs wishing to sell products receive a direct payment from the IOU according to the LSEs' proportional share of the realized sales revenues
- Option 2:
  - All customers pay full resource costs, less CAISO revenues, less the quantity of products in portfolio multiplied by PCIA product market price benchmark ("MPB")
  - LSEs wishing to take allocations must pay the PCIA product MPB for all products accepted as an allocation

PCIA Ratemaking Proposal Comparison



Assumes LSEs take allocation
Credits LSEs who sell allocation

Assumes LSEs sell allocation
Charges LSEs who take allocation

Long-Term Contracts and Rate Making Option 2

- Long-term sales can create the potential for cost shifts with Rate Making Option 2 when using the Market Price Benchmark approach, as adopted in Track 1, to set price that parties taking allocations should pay
  - MPB does not factor in sales that occur prior to N-2 period
  - Co-leads initially outlined an alternative "auction price benchmark" that addressed issue, but many parties have expressed interest in retaining current MPB construct
- CalCCA and SCE propose that the allocation price should factor in the weighted average price of historical* long-term transactions that occurred in periods prior to those considered in the MPB
  - Weighted average based upon quantity of RECs sold under long-term contracts in historical* periods that are still delivering vs. volumes sold in periods included in MPB
  - Conceptually, it can be thought of as the allocation participants having locked in a similar percentage of long-term pricing as represented in sales processes
  - Result is that parties taking allocations pay approximately their allocation percentage share of total contract costs

* Transactions entered into prior to N-2

Issue 2: Active Management of IOU Portfolios

PCIA Phase 2 - Working Group 3

IOU Portfolio Management Activities

- IOUs manage their portfolios on a short-term and long-term basis, consistent with AB 57, as well as their BPP and RPS Plans
- Each IOU currently maintains a team of professionals dedicated to managing its contract portfolio. Responsibilities include:
  - Ensuring terms and conditions are complied with;
  - Resolving disputes with counterparties; and
  - Identifying additional opportunities for cost reduction and value improvement
- The opportunity to modify a contract typically arises under three circumstances:
  - Either party requests a contract modification;
  - Buyer and/or seller identify an opportunity for a mutual benefit; or
  - Counterparty fails to perform
- Every contract, situation, and counterparty is unique
- Portfolio optimization activities require judgement, consideration of current market conditions, adherence to policies and Commission rules, and negotiation to be successful
  - Commission has imposed a reasonable manager standard for IOU portfolio management activities, as prescribed metrics cannot account for diversity of situations

Examples of Existing IOU Portfolio Optimization Activities

1. Enforcing rights due to events of default
2. Contract buy-outs
3. Change of contract term
4. Adjusting the contract capacity or facility design
5. Managing project design and timelines
6. Modifying site locations and/or on-line dates
7. Monitoring performance and enforcing compliance
8. Modifying equipment requirements
9. Incorporating economic curtailment rights
10. Managing force majeure claims
11. Reducing collateral requirements in exchange for an upfront payment
12. Other unique opportunities

Portfolio Management – Contract Assignments and Buy-Outs

- In addition to existing portfolio optimization practices, the co-leads propose to add an RFI process for contract assignments and buy-outs
- The process would have two parts
  - A process where IOUs would connect interested sellers with LSEs or other market participants who are interested in taking assignment of contracts from the IOU portfolio
  - An opportunity for sellers to propose contract-buy-outs
  - Process will be held annually for the first two years; after which the Commission to consider whether the process should be modified or continued
    - If continued, the process will be run every other year
- Resulting assignments or terminations would completely remove the contracts from the IOU portfolio
- IOUs would continue to have discretion to accept or reject any resulting proposal based upon existing AB 57 portfolio management standards
  - Any accepted offers will be subject to approval by the CPUC
- Details related to RFI process are still being discussed by co-leads

Contract Assignment Process Proposal

IOUs notify generators meeting certain criteria* of solicitation

→

Interested generators identify key conditions required for consideration of assignment

→

IOUs notify market of interested generators and preconditions

→

LSEs notify IOUs of interest in any contracts and ability to meet pre-conditions

→

IOUs connect interested sellers with qualifying LSEs, who negotiate an assignment of the contract or new contract

*Exclusions under consideration:

- Contracts priced below 115% of the Market Price Benchmark
- Contracts that if assigned will result in a shortfall in IOU RPS compliance

Issue 3: Transition to New Standards, if Identified

Issue 4: Shareholder Responsibility

Proposed Increase Reporting Standards

- The IOUs provide a variety of reporting of different events in their ERRA filings but the ERRA reporting may not be the same across all IOUs
  - Increased reporting
    - IOUs to report material events of defaults and any termination rights in ERRA compliance filings and any actions taken with respect thereto
    - Report cost savings from active portfolio management

Next Steps

Next Steps

- Co-Leads are seeking feedback on concepts presented by 12/20
  - Please submit informal comments through CPUC Service List

- Working Group 3 Next Steps:
  - Review informal comments received from workshop participants and refine proposals
  - Continue preparation of Final Report

- Upcoming Deliverables:
  - Final Report due January 30, 2020
  - Stakeholders comment on Final Report due 10 working days after filing Final Report [February 13, 2020] – to be confirmed by Commission
  - Commission Decision expected Q2 2020

Appendix E

INFORMAL COMMENTS TO FOURTH WORKSHOP PRESENTATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

ALLIANCE FOR RETAIL ENERGY MARKETS INFORMAL COMMENTS ON PCIA WORKING GROUP 3 MEETING #4

Scott Olson, Director, Western G&RA
DIRECT ENERGY BUSINESS, LLC
44 Montgomery St., 22nd Floor
San Francisco, CA 94104
Telephone: (510) 778.0531
scott.olson@directenergy.com

On Behalf Of the
ALLIANCE FOR RETAIL ENERGY MARKETS

20 December 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

ALLIANCE FOR RETAIL ENERGY MARKETS PCIA WORKING GROUP 3 WORKSHOP #4

The Alliance for Retail Energy Markets ("AReM") appreciates the opportunity to provide these informal comments on topics discussed in Workshop #4 of Working Group #3 ("WG3"), conducted on 11 December 2019 in San Francisco, California. AReM's comments below are focused on Local Resource Adequacy ("RA") allocation, rules for counting renewable resources as long-term, concerns that consideration of active management of Investor Owned Utility ("IOU") portfolios is incomplete, and remaining clarifications needed with respect to the PCIA calculation.

1. Local RA Allocation Should be Voluntary and Not Mandatory; If Mandatory, Only Former PG&E Other Resources Should Be Mandatory

While accepting an allocation of all other resource attributes (System/Flex RA, RPS, and GHG-Free resources) is voluntary for the LSEs offered the attributes, WG3 continues to propose that LSEs must accept Local RA allocations – that is, both the IOU offers of the Local RA attributes and the LSE acceptance of the offers – is mandatory. AReM does not believe that there is a need to treat Local RA differently from other resource allocations and asks the WG3 leads develop an approach where accepting a Local RA allocation is also on a voluntary basis. In addition, mandatory allocation acceptances run counter to Commission direction for what the Working Groups should consider[1], as outlined by DACC in its comments of 9 August.

Under the WG3 proposal, entities not needing their full allocation could sell to others, but that approach just exchanges one problem for another. Much like the IOUs today, there is no guarantee that those entities (i) will sell any excess they have, (ii) will have time to sell any excess they have given when the allocation occurs, (iii) will not keep the excess as a "buffer" for "uncertainty", or (iv) will not use allocated Local for System or Flex RA needs. Having a voluntary allocation process reduces these concerns as only entities with a need for the resources will pay for the allocation.

In addition, many LSEs may not need their allocation, especially in areas with increasing levels of CAM allocations. For example, all non-IOU LSEs are seeing their LA Basin Local RA requirements move considerably lower beginning in 2022 due to new CAM allocations. A mandatory allocation could then force non-IOU LSEs to take and pay through the PCIA for resources that they do not need.

During Workshop #4, it was stated by the WG leads that the mandatory acceptance of Local RA allocations approach came from a desire by the Northern California CCAs to have resources in the former "PG&E Other" locations[2] allocated to match specific needs without having an auction of any unallocated resources. If the WG leads and parties agree that this is the main reason for a mandatory allocation and if a voluntary allocation of Local RA is not preferred, the leads should consider a mandatory allocation of ONLY former PG&E Other Local RA and no

[1] D.18-10-019, Decision Modifying the Power Charge Indifference Adjustment Methodology, at p. 96.
[2] Former PG&E Other Local RA was disaggregated per D.19-02-022 into the Stockton, Sierra, North Bay/North Coast, Kern, Fresno, and Humboldt local capacity areas.

other Local RA mandatory allocations. All other Local RA allocations besides those in the former PG&E Other locations would then be done solely through a voluntary process.

2. Greater Active Management of IOU Portfolios

One of the key elements of minimizing PCIA related charges and optimizing utility portfolios that was to be included in WG 3 was active management of IOU portfolios. This entails contract assignments and buy-outs that would permanently remove the contractual resources from the utility portfolio and get the IOU resources more in line with the amount of load they are serving and expected to serve over the long term. In AReM's opinion this should have been the highest priority action of this WG as these mechanisms are the best way to actually "right size" the utility portfolios. "Right sizing" the IOU portfolios is only genuinely accomplished by getting portfolios in line with the amount of load being served. The markets for energy and capacity will work better if the IOUs return their excess to the market so that entities who need the supply can contract for it. There is no need for the IOUs to hold an "excess" or "buffer"; IOU customers will be made whole through the PCIA via payment for any above market contract costs, and any needed future procurement will be at the market price.

At Workshop #4, the co-leads described a proposal for the IOUs to conduct Requests for Information ("RFI"s) that would lead to contract assignments and buy-outs by connecting interested sellers with market participants interested in taking contract assignments or by allowing sellers to negotiate buyouts. The Workshop #4 presentation stated that the co-leads will continue to discuss the details of how an RFI process may work, but no details have been established as of yet. Since the final report of WG 3 is due by the end of January, this important topic is unlikely to be seriously vetted with interested parties, with important topics such (i) firm commitments or targets for divestitures, (ii) ensuring ensure that the parties to the existing contracts will be treated fairly and kept whole, and (iii) how the remaining stranded costs associated with divested contracts will be processed through the PCIA not discussed amongst stakeholders. To ensure that this important work gets done, AReM urges that the final WG 3 report develops a more concrete structure for divestment of excess IOU procurement, including discussion the topics listed above.

3. Only Long Term Renewable Contracts Should Receive Long Term Procurement Credits

The WG3 leads proposed in Workshop #4 that an entity that commits to take their Renewable Portfolio Standard ("RPS") allocation share through the life of their vintage will receive long-term procurement credits for all resources in that vintage provided that the longest RPS contract in the vintage has a remaining term of at least 10 years. AReM is concerned that it expands the quantity of RPS energy in the utility portfolio that qualifies for meeting the long-term contracting requirement to resources that are not actually long-term. If that is the case, AReM objects to this, as it could represent a significant change to the RPS long-term contracting rules. AReM members have already begun their procurement of resources for Compliance Period 4 from resources that meet the current definition of long-term RPS. Changing the rules now will diminish the values of these investments and penalize existing long-term procurement actions.

The WG3 leads stated in the 11 December workshop that the number of RPS contracts in each vintage with contract lives shorter than 10 years is small. AReM requests that the WG leads provide data on the number of short-term contracts which would now be classified as long-term by vintage if this proposal was to be applied.

4. Clarification of Use of Long Term Renewable Contracts in the PCIA Calculation

In the 11 December workshop, the WG leads proposed using "Option 2" for PCIA calculation with a new modification that will factor in the weighted average price of historical long-term transactions that occurred in periods prior to those considered in the RPS Market Price Benchmark ("MPB"). AReM's interpretation of the proposal is that the RPS MPB will not just include "reported prices from purchases and sales of renewable energy...during the year two years prior to the forecast year (year n-2) for delivery in the forecast year (year n)" (per D.19-10-018), but also include the sales price of any long-term contracts that are operating in year n. As an example, sales of a long-term RPS contract in 2020 with a term that runs through 2030 would have its sales price included in the MPB for years 2022-2030. AReM would like confirmation that this example matches the intent of the proposal, and would also like answers to the following questions:

- Will the proposal only apply to resources sold after a decision in WG3? Or will any long-term resource sold from the IOU portfolios in the past now be included in the MPB calculations?
- Would this modified MPB be used to calculate the RPS Adder used in the calculation of the PCIA for all entities, or only for the cost paid by an entity that voluntarily takes a long-term RPS allocation?
- How will this impact the MPB relative to the current RPS MPB? Please provide an estimate given recent transaction costs and recent MPB calculations.

AReM thanks the WG leads for their efforts and looks forward to a final report that addresses all the issues above and those in past sets of informal comments that have not been addressed.

Respectfully submitted,

Scott Olson, Director, Western G&RA
DIRECT ENERGY BUSINESS, LLC
44 Montgomery St., 22nd Floor
San Francisco, CA 94104
510.778.0531
scott.olson@directenergy.com

On Behalf Of the
ALLIANCE FOR RETAIL ENERGY MARKETS

20 December 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

COALITION OF CALIFORNIA UTILITY EMPLOYEES
INFORMAL COMMENTS ON PCIA PHASE 2 – WORKING GROUP 3, WORKSHOP 4

December 20, 2019

Rachael E. Koss
Adams Broadwell Joseph & Cardozo
601 Gateway Blvd., Suite 1000
South San Francisco, CA 94080
(650) 589-1660 Telephone
(650) 589-5062 Fax
rkoss@adamsbroadwell.com

Attorneys for Coalition of California Utility Employees

1011-1574j

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

COALITION OF CALIFORNIA UTILITY EMPLOYEES
INFORMAL COMMENTS ON PCIA PHASE 2 – WORKING GROUP 3, WORKSHOP 4

The Coalition of California Utility Employees (CUE) appreciates the opportunity to provide comments on the December 11, 2019, PCIA Working Group 3, Workshop 4 on portfolio optimization and auction and allocation. CUE's comments focus on the Working Group's proposal for IOUs to allocate RPS-eligible resources.

Slide 12 of the Working Group's presentation proposes that an LSE be able to receive a portion of or its entire RPS-eligible procurement obligation as an allocation from an IOU. The proposal contemplates that if the allocation includes just ***one*** contract with at least 10 years remaining, the ***entire*** allocated portfolio would count towards the LSE's RPS long-term compliance obligations. The Working Group's proposal is inconsistent with the RPS statute.

Public Utilities Code section 399.13(b) requires at least 65% of an LSE's RPS procurement to be from its contracts of at least 10 years. The Working Group's proposal opens the door for LSEs to circumvent this requirement and violate the law by packaging one long-term contract with any number of contracts that have less than 10 years left on them. However, the Commission does not have authority to modify the RPS long-term contracting requirement.

The Working Group should revise its proposal to eliminate any option for an LSE to satisfy its RPS long-term contract obligations with anything less than 65% of its contracts that are 10 years or longer.

Dated: December 20, 2019

Respectfully submitted,

/s/
Rachael E. Koss
Adams Broadwell Joseph & Cardozo
601 Gateway Blvd., Suite 1000
South San Francisco, CA 94080
(650) 589-1660 Voice
(650) 589-5062 Fax
rkoss@adamsbroadwell.com

Attorneys for Coalition of California Utility Employees

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

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

INFORMAL COMMENTS OF NEXTERA ENERGY RESOURCES, LLC ON PCIA WORKING GROUP 3, WORKSHOP #4

NextEra Energy Resources, LLC ("NextEra") provides the following informal comments on the portfolio optimization activities outlined on slides 24-26 in the presentation from the Workshop held on December 11, 2019. This includes, but is not limited to, the Request for Information (RFI) contract assignment proposal. NextEra appreciates the efforts of the co-leads, Southern California Edison Company, Commercial Energy, and California Community Choice Aggregation ("CalCCA"), and of the many others who have participated in this Working Group.

I. INFORMAL COMMENTS

NextEra continues to hold that in developing any portfolio optimization approach, parties should focus, as the Working Group sought to do at the outset, on the Commission's guiding principles identified in the Phase 1 Scoping Memo and Ruling of Assigned Commissioner, dated September 25, 2017 ("Phase 1 Scoping Memo"). In particular, NextEra supports the Commission's guidance that any methodology adopted through this process (i) should be consistent with California statutes, Commission decisions, energy policy goals, and mandates, and (ii) should respect the terms of existing power purchase agreements ("PPA") between power suppliers and IOUs.[1]

[1] Strawman Proposal at 3; Phase 1 Scoping Memo at 14 (establishing that any PCIA methodology adopted by the Commission "should respect the terms of existing power purchase agreements between power suppliers and IOUs").

Consistent with these principles, any portfolio optimization proposal, such as the RFI contract assignment process, should ensure that the commitments under existing renewable generation PPAs are preserved, and recognize that all counterparties have a legal right to reject re-assignment of their contracts. This is critical to ensuring market stability in the state to encourage continued development of renewables in order to meet California's clean energy and net-zero carbon mandates.

Developers of wind, solar, and other renewable electricity generation resources have made significant investments to build new generating facilities in California that produce electricity to meet increasing milestones under the California RPS. IOUs' execution of long-term PPAs for new renewable projects — and the Commission's approval of and assurance of rate recovery for those PPAs — provided a critical foundation that facilitated financing and construction of significant new renewable generating resources in California. In particular, the PPAs contain terms and conditions (including terms related to price, term, termination, assignment, change of control, event of default, creditworthiness, and consent) that are essential to continuing renewable generators' financing arrangements. Therefore, any portfolio optimization mechanism that contemplates adjustments to existing contracts, including but not limited to: contract re-assignment, buy-out of contracts, change of contracts terms, or adjusting the contract capacity or facility design, should be implemented in a manner that recognizes that PPA sellers may not agree to modifications of their existing contractual provisions.

The RFI contract assignment proposal from the December workshop presentation contemplates:

- IOUs would connect interested sellers with load-serving entities or other market participants who are interested in taking assignment of contracts from the IOU portfolio.
- Sellers would have an opportunity to propose contract-buy-outs.

- The process will be held annually for the first two years, after which the Commission would consider whether the process should be modified or continued.
- If continued, the process will be run every other year.
- IOUs would continue to have discretion to accept or reject any resulting proposal based upon existing AB 57 portfolio management standards.
- Any accepted offers will be subject to approval by the Commission.

It should be recognized, however, that each counterparty has a right to accept or reject changes to contract terms, or re-assignment or buy-out of its contract. Failure to do so would be in conflict with the Commission's guiding principles described above and with the current law. As a general matter, assignment of an existing PPA would require the consent of the seller (and most likely, its lenders) before any assignment can be completed. Any method such as the RFI re-assignment proposal must include a process that recognizes the PPA sellers' contractual right to consent to any such assignment or transfer, as well as requirements that the terms of the original PPA be maintained.

On slide 26 of the presentation, the co-leads allude to the fact that "interested" generators would be given the opportunity to "identify key conditions required for consideration of assignment." NextEra agrees that such a requirement must be a part of any such process at a minimum. As an initial step, the counterparty must first be consulted and agree to consider entering this process. The counterparty would also reserve the right to ultimately deny adjustment of contract terms, re-assignment, or a buy-out of its contract.

The Working Group 3 co-leads state that details for this process are still being discussed. As an impacted party, NextEra respectfully requests that the co-leads provide more detail on this proposal and an additional opportunity for comment on those further details before including the RFI contract assignment proposal in the final report, currently scheduled to be submitted on January 30.

II. CONCLUSION

NextEra appreciates the opportunity to provide informal comments here. The RFI contract assignment proposal and the other potential optimization activities listed on slide 24 are of serious consequence to developers and other counterparties to the contracts on which the state relies. Serious thought and effort must be put into any proposal that contemplates adjustment of contract terms, or re-assignment or buy-outs of these contracts. Neither the presentation from the December 11, 2019 workshop, nor the workshop itself, have provided sufficient information on these concepts. NextEra strongly encourages this working group to more fully develop this proposal before inclusion in its final report.

Dated: January 22, 2020

Respectfully submitted,

/s/ Lisa A. Cottle

Lisa A. Cottle
Winston & Strawn LLP
101 California Street, 35th Floor
San Francisco, CA 94111-5840
Telephone: (415) 591-1579
Facsimile: (415) 591-1400
Email: lcottle@winston.com

Tracy C. Davis
Senior Attorney
NextEra Energy Resources, LLC
5920 W. William Cannon Dr., Bldg. 2
Austin, TX 78749
Telephone: (512) 236-3141
Facsimile: (512) 236-0484
Email: tracy.c.davis@nexteraenergy.com

Attorneys for NextEra Energy Resources, LLC

Public Advocates Office
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102
Tel: 415-703-1584
www.publicadvocates.cpuc.ca.gov

THE PUBLIC ADVOCATES OFFICE'S COMMENTS
ON *PCIA PHASE 2 WORKING GROUP 3*

R.17-06-026

Submitted by	**Organization**	**Date Submitted**
Mea Halperin Senior Analyst Phone: (415) 703-1368 Email: Mea.Halperin@cpuc.ca.gov Sonya Ziaja Senior Analyst Phone: (415) 703-1271 Email: Sonya.Ziaja@cpuc.ca.gov Public Advocates Office California Public Utilities Commission 505 Van Ness Avenue San Francisco, CA 94102	Public Advocates Office – California Public Utilities Commission	December 20, 2019

The Public Advocates Office submits the following informal comments in response to the December 11, 2019 Fourth Workshop for the Power Charge Indifference Adjustment (PCIA) Working Group Three: Portfolio Optimization and Cost Reduction, Allocation, and Auction. This workshop largely summarized the ongoing scoping issues discussed during the previous three workshops, and the co-chairs proposed some new recommendations. Of these recommendations, the Public Advocates Office opposes imposing the PCIA cap during the portfolio optimization process, as well as changing the Energy Resource Recovery Account (ERRA) reporting requirements outside of the ERRA proceeding. The Public Advocates Office also opposes two proposals related to the sunset of the PCIA and enforcement of reporting requirements submitted by the Protect Our Communities Foundation (POC) in its November 4, 2019 filing.[1]

Application of PCIA Cap During Portfolio Optimization Process

According to the PCIA Phase 1 Decision, the PCIA cap is set at 0.5 cents/kWh more than the prior year's PCIA (differentiated by vintage), and any PCIA amount that exceeds the cap will be tracked in a separate balancing account for recovery from departing load customers at a future date.[2] In the event that an investor-owned utility (IOU) projects the PCIA will exceed 10% of its forecast PCIA revenues and will not self-correct, the IOU must submit an application proposing a revised PCIA rate that will bring, and maintain, the account balance below 7% until January 1 of the following year.[3]

Although the portfolio optimization process runs the risk of causing the PCIA to spike, it is not reasonable to implement the PCIA cap for the costs incurred during this process. While stable rates would benefit departing load customers, a cap on the PCIA results in short-term cost spikes for bundled service customers. This is because any PCIA amount not paid by the departing load customers must be paid in the interim by bundled service customers until the balance is repaid to bundled service customers, with interest.[4] While this may be reasonable for PCIA overages incurred during regular energy market transactions, the scale of the portfolio optimization market offer transactions places bundled service customers at risk of paying significantly increased rates in the short-term which would result in rate instability for bundled service customers. Furthermore, if the portfolio optimization transactions activate the PCIA trigger mechanism, the revised rate that would bring the PCIA account balance below 7% may lead to departing load rate spikes anyway.

Instead, the parties must approach portfolio optimization in a similar manner to prepayment; that is, a departing load party must pay up-front for resources offered in the voluntary market, and seek cost recovery from its customers outside of the PCIA. Portfolio

---

[1] POC proposes (1) that the PCIA sunset in 5 years and (2) all proposals include automatic enforcement and shareholder responsibility mechanisms. (Protect Our Communities Foundation's Proposals for Portfolio Optimization [POC Proposal], November 4, 2019.)

[2] D.18-10-019, Ordering Paragraph (OP) 9, p. 162.

[3] D.18-10-019, Ordering Paragraph (OP) 10, pp. 163-164.

[4] D.18-10-019, p. 86.

optimization is a voluntary process, and bundled service customers must not be forced to pay the short-term excess costs from elective market transactions.

Increased ERRA Reporting Requirements

The co-chairs propose that the IOUs report additional information in their annual ERRA filings, including "material events of defaults and any termination rights in ERRA compliance filings" and "cost savings from active portfolio management."[5] This recommendation is inappropriate for the PCIA proceeding; any changes to ERRA compliance requirements must be addressed within the ERRA proceeding through a Petition for Modification, or other similar mechanism, with ample opportunity for parties to participate and comment.

While the co-chairs are correct that the information in the IOUs' ERRA Compliance filings "may not be the same across all IOUs,"[6] this is because the IOUs engage in different types of transactions in a given Record Period, and the activities they report vary based on the status of their contracts and the events that took place during the Record Period. However, the reporting *requirements* are the same across all IOUs. The IOUs are already required to report the details of their contract administration activities in a given Record Period, including "material events of defaults and any termination rights,"[7] as well as the management of their utility-owned generation (UOG) resources,[8] least-cost dispatch,[9] greenhouse gas (GHG) compliance obligations,[10] and accounting activity.[11] In short, ERRA Compliance is complex, long-running, and the proceedings often involve multiple parties. Any changes to the ERRA process must be proposed and addressed within the ERRA framework.

Protect Our Communities' Proposal

[5] PCIA Phase 2 Working Group 3, Workshop No. 4 Presentation, December 11, 2019, slide 28.
[6] PCIA Phase 2 Working Group 3, Workshop No. 4 Presentation, December 11, 2019, slide 28.
[7] D.11-10-002.
[8] D.11-10-002.
[9] D.05-01-054, D.15-05-005, D.15-05-006, D.15-05-007.
[10] D.12-04-046
[11] D.02-10-062.

POC submitted a proposal for portfolio optimization on November 4, 2019, which includes a plan to sunset the PCIA in five years.[12] The Commission already considered, and rejected, the notion of a PCIA sunset provision in Phase 1, as discussed in D.18-10-019:

> [W]e agree … that [Public Utilities Code] Section 366.2(f)(2) bars the Commission from sunsetting CCA customer obligations vis-à-vis "the expiration of all then existing electricity purchase contracts." We also agree … that a sunset provision will reduce incentives for parties to actively participate in any allocation or auction process that may take place in the second phase of this proceeding.[13]

These reasons for rejecting the PCIA sunset are still applicable.

Additionally, POC raises several proposals for "automatic enforcement of the co-chair's allocation and auction proposal."[14] Specifically, POC proposes that if IOUs miss reporting deadlines, bundled and unbundled customers would automatically receive bill credits within 60 days of the missed deadline, paid for by the IOU's shareholders, "without the need for any Commission action."[15] While the Public Advocates Office favors oversight of the IOUs to ensure just and reasonable rates, it does not support the enforcement mechanisms proposed by POC.

At its core, POC's proposal is primarily concerned with oversight of IOU energy procurement to prevent waste.[16] However, compliance mechanisms already exist within the Commission's procurement framework – such as the ERRA forecast and compliance proceedings,[17] the integrated resource planning (IRP) process,[18] and utility-scale Request for Offers (RFO) and solicitations[19] – to ensure that IOUs' reports and actions are timely and transparent. Therefore, the Public Advocates Office recommends that the working group co-chairs reject the enforcement aspects of POC's proposal.

---

[12] POC Proposal, pp. 3-5.
[13] D.18-10-092, p. 82.
[14] POC Proposal, p. 2, 6-7.
[15] POC Proposal, p. 6.
[16] POC Proposal, p. 1 (e.g., "If an IOU's portfolio of PCIA-eligible resources is so mismanaged that 23 years after the legislature enacted AB 117 it still includes excess resources, then that IOU's shareholders should be responsible for the cost of those resources.").
[17] https://www.cpuc.ca.gov/General.aspx?id=10430
[18] https://www.cpuc.ca.gov/irp/
[19] https://www.cpuc.ca.gov/Utility_Scale_RFO/

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE
PCIA PHASE 2, WORKING GROUP #3, WORKSHOP #4

M. GRADY MATHAI-JACKSON
KRISTIN D. CHARIPAR

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 973-5520
E-Mail: grady.mathai-jackson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: December 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE
PCIA PHASE 2, WORKING GROUP #3, WORKSHOP #4

Pacific Gas and Electric Company ("PG&E") provides the following informal comments on the Power Charge Indifference Adjustment ("PCIA") Phase 2, Working Group Three, Workshop #4 held on December 11, 2019 (the "Workshop"). PG&E lauds the work by Southern California Edison Company ("SCE"), the California Community Choice Association ("CalCCA") and Commercial Energy (collectively, the "Co-Leads"), to develop an initial framework for the allocation of system, local and flexible resource adequacy ("RA"), greenhouse gas ("GHG")-free, and renewables portfolio standards ("RPS") attributes, and appreciates the ability to provide comments.

As described below, PG&E describes below its concerns with certain elements of the revised proposal and offers general feedback on the market offer component of the proposal. In particular, these comments address PG&E's recommendations on the following issues:

1. PG&E supports a simpler mechanism for allocating out the costs and benefits to all customers; if not, Co-Leads should clarify proposals;
2. Further clarification of the existing proposal, including real-world examples, is necessary to determine if implementation is feasible;
3. The ratemaking challenges associated with the current proposal have not been explored and require additional review;

4. PG&E supports treating commission-approved and mandated allocations of renewable energy credits from long-term contracts in the IOUs' portfolios as long-term as to the receiving LSE;
5. The spring partial voluntary allocation and market offer does not have sufficient detail;
6. Increased reporting is not necessary, given the level of detail already provided in the Energy Resource Revenue Account ("ERRA") Compliance Review Application;
7. IOUs canvassing generators could create an excessive administrative burden and the IOUs should retain sole discretion for reassigning contracts; and
8. The shareholder plan developed by Protect Our Communities Foundation's ("POC") proposal should be dismissed.

PG&E looks forward to continuing to engage in this process and working through some of the important implementation details with parties, potentially as another phase of the Working Group process.

I. PG&E SUPPORTS A SIMPLER MECHANISM FOR ALLOCATING OUT THE COSTS AND BENEFITS TO ALL CUSTOMERS; IF NOT, CO-LEADS SHOULD CLARIFY PROPOSAL

The current Voluntary Allocation, Market Offer (VAMO) proposal put forth by the Co-Leads) represents many weeks of intense and impressive collaboration between the Co-Leads and other parties. PG&E appreciates the work that has been put in to develop the VAMO framework particularly given the diverse interests of the stakeholder group. However, at this point PG&E recommends looking for ways to simplify the proposed framework to ensure that it works within the existing regulatory and market. For example, Co-Leads should consider whether it is necessary for both the allocation to be voluntary and for products to be tradable after the fact; each of these attributes adds significant complexity and they seem to achieve the same thing (flexibility for CCAs and DAs). A mandatory allocation of tradable products would likely be far simpler and quicker to implement than the current proposal.

If the co-Leads do not simplify the proposal, PG&E recommends clarifications and changes to the proposal as shown below. Most of these recommendations are for clarity. The addition of the allocation of the GHG-emitting attribute is something that should be addressed to prevent "cherry-picking" of the PCIA portfolio and unexpected results on the Power Content Label ("PCL") (e.g., greenhouse gas emissions that do not show up on any load serving entities PCL). PG&E also recommends that for any firm allocations or sales, Co-Leads clearly spell out mechanisms to prevent risk shift to bundled customers. Finally, the terms for all products are limited to 1-year in the VAMO to allow for continued optimization of the PCIA portfolio; any long-term sales through the auction would prevent the IOU from portfolio optimization activities such as the propose Request for Information ("RFI") process. PG&E's suggested changes to the current proposal from the Co-Leads are in *italics* and red font.

TABLE 1
SUMMARY OF THE VOLUNTARY ALLOCATION AND MARKET OFFER PROPOSAL FOR THE IOUS' RESIDUAL PCIA-ELIGIBLE PORTFOLIO

	Local RA	**System/Flex RA**	**RPS**	**GHG-free**	***GHG-emitting***	***Energy***
Pro rate vintage share	Peak-load	Peak-Load	Forecasted Annual Load Share	Forecasted Annual Load Share	*Needs further develop-ment*	*Actual Load*
Allocation	Mandatory	Voluntary ~~*(all or portion)*~~ *on behalf of the receiving LSE (in 10% increments)*	Voluntary ~~*(all or portion)*~~ *on behalf of the receiving LSE (in 10% increments)*	Voluntary ~~*(all or portion)*~~ *on behalf of the receiving LSE (all or nothing)*		*Mandatory*
Market Offer	N/A	Monthly or Annual	~~Long-term and~~ *Annual*	N/A		*N/A (CAISO Market)*

Unit Contingent or Firm	*Year 1: Firm Years 2 and 3: Unit contingent*	*Spring[1]: Unit continent Fall: Firm*	*Unit continent*	*Unit contingent*		*Unit Contingent*
Risk Mitigation for Firm Product	*Shared penalties*	*Shared penalties*	*N/A*	N/A		*N/A*
Term	*3 years (100% Year N, 100% N+1, 50% N+2)*	*1 year*	*Allocation: vintage or 1 year; Market Offer: 1 year*	*1 year*		*1year*

[1] The Spring auction should only occur if the issues described in these comments are resolved.

Finally, the Co-Leads should clarify in the Final Report that the Working Group 3 VAMO applies to the investor owned utilities' ("IOU") residual PCIA portfolio, i.e., the portfolio that remains after IOUs conduct portfolio optimization activities, which could include sales. Long-term sales or fixed volume allocations in VAMO would restrict the ability of the IOU to divest resources, assign contracts, buy out contracts, sell products through other competitive processes, or otherwise reduce the size of the PCIA portfolio and should not be adopted as part of the proposal. For example, if PG&E sells a long-term RPS product through the VAMO, it cannot then assign or allow a buy-out the underlying contract.

II. FURTHER CLARIFICATION OF THE EXISTING PROPOSAL, INCLUDING REAL-WORLD EXAMPLES, IS NECESSARY TO DETERMINE IF IMPLEMENTATION IS FEASIBLE

PG&E supports an implementation phase for the portfolio optimization and VAMO framework. The Co-Leads have developed a thoughtful framework that helps move forward the goals of PCIA proceeding. However, implementation of the proposal will be complex, with a very high likelihood that details that will need to be further clarified and resolved. This is needed to avoid any unintended consequences and determine when the California Public Utilities Commission ("the Commission") and load serving entities ("LSEs") will be ready to implement the proposal. Specifically, PG&E recommends the implementation phase focus on providing examples in order to further clarify the following topics and answer the following questions:

- Timeline

    - How will the VAMO interface with the existing RA market timeline for both CPUC and California Independent System Operator ("CAISO")?

    - If the RA timing needs to move up, as indicated in Slide 18 to the Fourth Workshop Presentation, what steps would be needed for that to occur and what timing of implementing those changes?

- Administration and additional costs

    - How would the cost of administering the auction be decided and what would the cost recovery and cost allocation look like?

    - Are the IOUs required to run the market offer? What sort of walls would need to be put in place for the IOUs to run the market offer and participate in it? Could the administration be outsourced to a third-party?

    - Would there be three separate auctions for each IOU, or could there be one across all three IOUs? If there are three separate auctions, are there any timing or sequencing issues for state-wide products?

- Specific Examples

    - If required, how would the long-term sales through the VAMO work with the proposed Request for Information process?

    - How will the prepayment (Working Group 2) fit in?

    - What happens if all parties elect to take their allocation for the voluntary products?

    - What happens if no parties elect to take their allocation for the voluntary products?

    - What happens if no parties bid in the auction?

    - How do the long-term allocation and the recently proposed Request for Information[1] process work in concert?

    - Does the IOU maintain sole discretion in its role as scheduling coordinator for the PCIA resources? Will there be cost caps for substitute RA, for example?

---

[1] See December 11 Co-Lead Presentation at page 25.

- What happens if there is no substitute RA available for a forced outage or a cancelled planned outage? How is the CAISO/Federal Energy Regulatory Commission compliance risk shared?
- Would the RA VAMO process change with the implementation of a Central Buyer? Would there be a process to revisit whether the complexity of the VAMO continues to be necessary with a Central Buyer in place?
- If Ratemaking Option 2 is adopted, what measures can be put in place to ensure that the IOU is paid? If the IOU is not paid in a timely manner, will the costs be socialized?
- What happens to the VAMO process if an LSE suddenly stops serving customers?

III. THE RATEMAKING CHALLENGES ASSOCIATED WITH THE CURRENT PROPOSAL HAVE NOT BEEN EXPLORED AND REQUIRE ADDITIONAL REVIEW

The Co-Leads have proposed two ratemaking options for the VAMO proposal. Under Ratemaking Option 1, when an LSE takes the allocation, the attribute values for RPS and RA in the indifference calculation are zero, which differs from the current construct where the RPS and RA attributes are assigned a value based on the Commission-approved Market Price Benchmark (MPB). PG&E prefers Ratemaking Option 1 because it minimizes the ratemaking and administrative complexity, which is not insignificant, and arrives at a fair allocation of the costs and benefits of the portfolio.

The modified Ratemaking Option 2 presented at the December 11, 2019 Workshop continues to rely on a market price benchmark (MPB) for energy, renewable portfolio standard (RPS) attributes, and resource adequacy (RA) attributes, and yet expands the administrative complexity. The Co-Leads propose to expand the data used to calculate RPS value beyond the n-2 framework approved in Decision (D.) 19-10-001. Specifically, the Co-Leads recommend that the allocation price should factor in the weighted average price of "historical" long-term transactions that occurred in periods prior to those considered in the currently approved MPB, which considers transactional data for periods up to n-2 where "n" is defined as the forecast year.

The historical period under consideration in the Co-Lead presentation suggests that the periods would be tied to any long-term contracts sold under the VAMO that are still delivering RPS for the prompt year.[2] It is not clear whether or how the proposal would incorporate the requirement from D. 19-10-001 to examine long-term bundled RPS value.

It appears that the problem the modified proposal is trying to address is the ability to have the RPS attribute value reflect a long-term sales prices made through the VAMO to ensure those LSEs that decide to commit to a long-term allocation pay a weighted average attribute value that reflects long-term sales activity on a weighted average basis. That is, the proposal would not only include the current n-2 transaction market values but would also include any sales activity coming out of the VAMO process. PG&E opposes the requirement to sell long-term products through the VAMO as this requirement prohibits the ability to perform portfolio optimization activities, as explained above.

In addition to opposition to the underlying assumption that the VAMO should include long-term sales, PG&E has reservations on the administrative complexities associated with implementing such a methodology and whether the proposal will have unintended consequences which might result in an MPB for the RPS attribute that is not current or skews the market value far afield from the current market value, which was a flaw in the previous MPB approved in D.11-12-018 for RPS attributes. The previous methodology's attribute price was based primarily (68 percent weighting) on newly delivering contracts that were signed 3 to 6 years prior to the current year's PCIA forecast. The criticism for this methodology was that the stale attribute pricing was not reflective of the current market value, which caused cost shifts between bundled customers and departing customers.

---

[2] See December 11 Co-Lead Presentation at page 21.

Another concern would be situations where there are no LSEs taking long-term allocations, yet the methodology is dogmatically implemented to include the VAMO long-term contract pricing to solve the price parity issue for LSE's taking allocations, yet there are no LSEs long-term allocations to worry about.

Lastly, it is not well defined in the presentation whether the modified Option 2 would apply only to the RPS attributes, which the VAMO would be selling long-term, but it is unclear whether the proposal would also apply to any long-term RA sales. PG&E would request that the Co-Leads clarify if the modified Ratemaking Option 2 proposal could potentially apply to any long-term RA products.

PG&E notes that none of these issues regarding benchmark values exist with Option 1 because Option 1 does not use benchmarks. PG&E continues to recommend Option 1.

IV. PG&E SUPPORTS TREATING COMMISSION-APPROVED AND MANDATED ALLOCATIONS OF RENEWABLE ENERGY CREDITS FROM LONG-TERM CONTRACTS IN THE IOUS' PORTFOLIOS AS LONG-TERM AS TO THE RECEIVING LSE.

The Co- Chairs propose that "in order for an LSE to receive the 'long-term' benefits from RPS allocation, they must elect to receive their allocation share through the life of their vintage."[3] The Co- Chairs note that under their proposal, short-term allocations would not count as long-term for the LSE receiving the allocation.

The RPS statute, as revised in 2015 by Senate Bill 350, includes a "long-term" procurement requirement in Section 399.13(b). That provision requires that, beginning January 1, 2021, at least 65 percent of a retail seller's procurement be from "its contracts of 10 years or more in duration or in its ownership or ownership agreements" for RPS-eligible

[3] Workshop presentation, Slide 12.

resources. While the Commission has implemented this requirement in Decision 17-06-026, it did not expressly decide there whether and how Renewable Energy Credits (RECs) that are allocated through a Commission-mandated cost allocation process like the PCIA should be treated for purposes of the long-term procurement requirement of the LSE receiving the allocation.[4] This is not surprising given that the allocation of RECs had not yet been authorized for the PCIA or any other Commission-mandated cost allocation mechanism as of the time of that Decision; rather, the value of RECs has been determined through either an administratively-set price or through the sale of the RECs by the IOU, and then the ascribed value has been credited toward the net cost of the contract that is allocated to the LSEs.

The Working Group 3 proposal requires the Commission to directly address this issue and to further interpret the statutory long-term procurement requirement in the context of allocated renewable energy credits ("RECs"). PG&E submits that any such further interpretation be narrowly confined to the situation at hand: the mandatory, Commission-authorized allocation of RECs from long-term contracts in the IOUs' portfolios through a Commission-approved allocation mechanism. In other words, the final Working Group 3 proposal should specifically address the non-precedent-setting nature of this treatment and should ask the Commission to limit the ability of RECs allocated from contracts with less than 10 years remaining to count as long-term only in the context of Commission-mandated cost allocation. Any other transfers or sales of RECs, including those RECs sold through any Market Offer aspect of the Working Group 3 proposal (if this aspect of the proposal is preserved), should continue to be subject to the ordinary long-term rules requiring contractual commitments of at least 10 years.

---

[4] *See* D.17-06-026, pp. 15-25 (discussing definition and characterization of "long term" procurement and ownership commitments for purposes of implementing Section 399.13(b), but not addressing Commission-mandated REC allocations as part of the PCIA).

There is a logical basis for distinguishing mandatory PCIA REC allocations from other types of voluntary REC sales. The long-term contracts in each PCIA vintage represent contractual commitments entered into for at least 10 years by an IOU on behalf of all of its bundled customers at the time of execution. That includes customers that subsequently departed from IOU bundled service and chose to take service from other LSEs. By so departing, those customers then became subject to the PCIA because they remain responsible for the portion of the IOU's procurement undertaken by the IOU prior to the customer's decision to depart. The Working Group 3 Proposal now suggests allocating the same RECs that were procured originally on behalf of departed load to those same departed load customers. This is reasonable because those customers are paying through the PCIA for the long-term RPS contracts that were procured on their behalf.

Given this perspective, PG&E sees no statutory barrier to the Working Group 3 proposal for RPS Long-Term Attribute Preservation, so long as the Commission makes clear that this interpretation only applies in the context of Commission-mandated cost allocation. This is true even if some or all of the RPS contracts in a particular vintage have less than 10 years remaining in deliveries. The original contract, when entered into by the IOU on behalf of the departed load customer, was long-term, and it supported the planning and financing stability goals underlying the long-term requirement, as further described in D.17-06-026. Allocation of the RECs associated with that long-term contract should remain long-term as to the receiving LSE. Any further sale of the same RECs by the receiving LSE would be subject to the usual long-term duration requirements to determine if the buyer of those RECs could count it as long-term.

V. THE SPRING PARTIAL VOLUNTARY ALLOCATION AND MARKET OFFER DOES NOT HAVE SUFFICIENT DETAIL

The Co-Leads presented a very high-level explanation as to how the Spring VAMO would occur.[5] PG&E requests additional details on how the spring VAMO would work in relationship to ongoing sales as a part of the IOUs portfolio optimization along with the CAISO and Commission require adjustments that transpire between Q1 and mid-September. Further details on how the allocations would be determined in Q1 needs to be discussed, as without a prescriptive method the values would be subject to dispute and potential litigation leading to unnecessary costs to customers.

The Co-Leads correctly point out that "there is only a short window for procurement between receiving RA obligations and the year-ahead RA showing" and the intent of the spring VAMO is good, i.e. to help relieve the pressure on the fall VAMO and RA market. Examples would greatly assist in understanding how the spring market offer could occur. For instance, when an LSE accepts the allocation, but it then opts-out of its allocation in the fall, how and when would the requirements adjust? And how would that impact the timing of the fall VAMO and the ongoing RA market? Or, if there are significant methodological changes to calculating net qualifying capacity ("NQC") or effective load-carrying capability ("ELCC"), then how would the allocations be adjusted? Should all the allocations in the spring be unit contingent to address issues with hydro counting rules? As discussed above, examples are needed to help clarify some of these thorny issues and the Co-Leads and Commission should consider an implementation phase following the Working Group 3 final decision.

VI. INCREASED REPORTING IS NOT NECESSARY, GIVEN THE LEVEL OF DETAIL ALREADY PROVIDED IN THE ERRA COMPLIANCE REVIEW APPLICATION

Limited detail was provided on the specific changes that are desired as part of compliance filings in the ERRA proceedings.[6] This section provides several considerations that the Co-Leads may want to incorporate into their proposal.

---

[5] Workshop presentation, Slide 18.
[6] See Workshop Presentation, Slide 28.

The ERRA Compliance Review Application provides detail on the defaults that lead to terminations of contracts. It is not clear what types of defaults require reporting under the proposal, but additional reporting on all defaults, including those that do not result in terminations, may not provide meaningful insights and could create an undue burden on the IOUs. Defaults in contracts happen, but so does the curing of those defaults by counterparties. Furthermore, limited detail was provided for the recommendation to "report cost savings form active portfolio management." Again, more detail is needed to determine what is being requested, but PG&E's initial thinking is that the current ex ante assessment in the ERRA Compliance Review Application is adequate to evaluate cost savings from utility portfolio management activities.

VII. CANVASSING GENERATORS COULD CREATE AN EXCESSIVE ADMINISTRATIVE BURDEN AND THE IOUS SHOULD RETAIN SOLE DISCRETION FOR REASSIGNING CONTRACTS

As part of Workshop #4, the Co-Leads put forward a proposal under which an IOU would be obligated to regularly solicit interest from its contractual counterparties regarding assignments or buy-outs of those contracts. The purpose of this RFI would be to put any such interested counterparties into contact with other non-IOU LSEs that may be interested in taking assignment of the contract or entering into a new contract with the generator.

PG&E opposes the RFI proposal because it forces the IOUs into a position of serving as a market platform provider in a manner that is (i) uncompensated; (ii) creates administrative costs and (iii) not needed for bundled customers. Should the Commission adopt an RFI framework, there is a need to limit the number of participants that engage in the RFI at any given period. Due to limited resources of the IOUs, an 'open season' or some other framework that helps limit the number of parties that are participating in the RFI at any given period would be needed.

The sole discretion to enter into any contract reassignments or novations should remain with the IOUs, subject to the Commission's oversight of the reasonableness of an IOU's contract administration. The purpose of PCIA is to fairly share the benefits and costs of the IOU portfolios that have been acquired for customers across all LSEs. An integral criterion to focus on is the optimization of the IOU portfolios. The aim is not for the IOUs to optimize portfolios for all the LSEs. Thus, when the IOUs determine, based on their sole discretion, that there is a desire to maintain any contract within its portfolio, that determination should be assessed against existing prudent manager criteria and not on new criteria (i.e., from the proposed RFI process).

If the RFI is adopted, the Co- Leads should clarify what the timing of the RFI would be and how it would work in terms of the VAMO and existing portfolio optimization practices. would help, along with examples of different scenarios that may transpire (e.g. a contract that is under sales negotiations that are then included in the RFI).

VIII. THE SHAREHOLDER PLAN DEVELOPED BY PROTECT OUR COMMUNITIES FOUNDATION SHOULD BE DISMISSED

The POC proposal for shareholder penalties raises significant concerns. First, it appears that under this proposal penalties could be imposed irrespective of actions outside the sole control of the IOUs. This might include, for example, changes to the NQC or ELCC list or other changes to compliance rules or processes adopted by the CAISO, the California Energy Commission, or the Commission that impact the process or timing of the VAMO. Adopting an "automatic" penalty as proposed by POC would hold IOUs to an unreasonable standard in light of these potential regulatory changes. Second, instituting automatic penalties runs a high risk of violating an IOU's right to due process, if those penalties are applied without any opportunity of the IOU to provide mitigating evidence or explanations. Third, POCs argument to eliminate the PCIA cost recovery eligibility in five years ignores the fact the Commission rejected similar arguments in Phase 1 of this rulemaking proceeding. In D.18-10-019, the Commission rejected the CCA parties' arguments to sunset departing load customers' PCIA obligation, and determined that "a [sunset] provision should not be adopted in this decision".[7] In arguing that the IOUs should eliminate any excess procurement in their portfolios on a set, near-term timeframe, POC's Portfolio Optimization proposal fails to consider the contractual commitments

---

[7] *See* D.18-10-019, p. 82 (Finding of Fact 18); *see also id.*, pp. 60-61 (noting that "customer indifference requires the equitable distribution of all stranded costs among customers for whom those costs were incurred").

that the IOUs have entered into on behalf of all then-bundled customers that extend beyond a 5-year. POC's proposal is unworkable in light of these commitments and fails to recognize the ongoing activities undertaken by the IOUs consistent with Standard of Conduct 4 of their respective Bundled Procurement Plans. It is for these reasons that PG&E believes that POC's proposal should be rejected.

IX. CONCLUSION

PG&E respectfully requests that these informal comments inform the Commission's consideration of the allocation and market offer mechanism proposal. PG&E looks forward to collaborating with the Co-Leads and all other participants in the PCIA discussions.

Respectfully Submitted,

By: /s/ M. Grady Mathai-Jackson
M. GRADY MATHAI-JACKSON

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 973-5520
E-Mail: grady.mathai-jackson@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: December 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

PROTECT OUR COMMUNITIES FOUNDATION'S COMMENTS ON AND PROPOSALS FOR PORTFOLIO OPTIMIZATION

Tyson Siegele
Energy Analyst
Protect Our Communities Foundation
tyson@protectourcommunities.org

Ellison Folk
Yochanan Zakai
SHUTE, MIHALY & WEINBERGER LLP
Folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: December 20, 2019

TABLE OF CONTENTS

Page

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

PROTECT OUR COMMUNITIES FOUNDATION'S COMMENTS ON AND PROPOSALS FOR PORTFOLIO OPTIMIZATION

I. Introduction

On December 11, 2019, the co-chairs of Working Group 3 convened a workshop at which they requested that parties submit comments on their portfolio optimization proposals via informal comments to the service list by December 20, 2019. Protect Our Communities Foundation (POC) submits these comments pursuant the schedule set by the co-chairs. These comments first address the co-chairs' portfolio optimization mechanism, then POC's automatic enforcement mechanism, and finally refinements to the co-chairs' voluntary allocation and market offer proposal.

Portfolio optimization mechanisms should promote the sale of Power Charge Indifference Adjustment-eligible resources in a manner that ensures the greatest value for customers. As a first priority, investor-owned utilities (IOUs) should sell entire resources, which would create the most value for customers who would otherwise pay the full cost of those resources through the Power Charge Indifference Adjustment (PCIA). Secondarily, portfolio optimization mechanisms should also capture the full value of all resources' attributes on a short-term basis through the voluntary allocation and market offer mechanism. Accordingly, IOUs should continue to perform long-term portfolio optimizations that include the sale of entire resources and buyout of power purchase contracts outside of the co-chairs' proposals.[1]

II. POC supports the co-chairs' proposal that IOUs issue a request for information for contract assignment and buy-outs.

The co-chairs propose a process where IOUs are required to issue a request for information (RFI) for contract assignment and buy-outs.[2] This process would connect interested sellers with other market participants interested in receiving an assignment of a resource contract. It would also provide an opportunity for sellers to propose contract buy-outs. POC supports this proposal as one of many potential vehicles for IOUs to assign or buy-out entire resources. POC agrees that these assignments and buy-outs, which would remove a contract from an IOU's portfolio in perpetuity, should take priority over any allocations or auctions made pursuant to the annual voluntary allocation and market offer mechanism.

A. Contract buy-out costs are subject to the PCIA cap.

The cost of any contract buy-out made pursuant to this proposal would be subject to the PCIA cap. Southern California Edison's (SCE's) contention at the workshop that the PCIA cap does not apply to contract buy-outs is wrong. In its phase 1 decision, the Commission established a cap on annual increases to the PCIA rate to "reduce extreme PCIA price spikes, and bill impacts" and "protect[] against volatility in the PCIA."[3] Nothing in D.18-10-019 allows or suggests that any costs properly included in the PCIA are exempt from the cap. Moreover, nothing in the Commission's discussion of the cap's accounting suggests that utilities should set

---

[1] R.17-06-026, PCIA Phase 2 –Working Group Three Portfolio, Optimization and Cost Reduction, and Allocation and Auction, Refinement of Issue 1 Proposals; Issues 2-4, Workshop No. 4, Presentation at 9 (December 11, 2019) (December 11, 2019 Presentation).

[2] December 11, 2019 Presentation at 25-26.

[3] R.17-06-026, D.18-10-019, Decision Modifying the Power Charge Indifference Adjustment Methodology, at 85-86 (October 19, 2018).

up accounting mechanisms to track PCIA costs outside of the cap because the Commission did not authorize any PCIA costs to be outside of the cap.

Further, IOUs are not harmed by the cap because the Commission ordered ratepayers to pay for the full cost of any PCIA rate above the cap—including interest—over time.[4] The IOUs' investors will be compensated at the Commission-approved rate of return for any debt issued to cover short-term buy-out costs that are unrecovered. The IOUs should welcome the opportunity to earn a return on debt issued due to the PCIA cap rather than arguing against rate stability for unbundled customers.

B. Only contracts priced below the market price benchmark should be excluded from the request for information.

POC supports requiring low-priced contracts to be retained by IOUs for the benefit of customers. To meet this goal, the co-chairs are considering excluding contracts priced below 115% of the market price benchmark (MPB) from the RFI mechanism.[5] POC recommends that the co-chairs set this percentage at 100% instead of 115%. The co-chairs have not articulated a rationale for setting the cut-off at 115% and POC is concerned that this may foreclose the possibility of an IOU divesting itself from a contract that is above the market price. This threshold will be used to determine which contracts are included in the RFI, not which contracts are ultimately selected by the IOU for assignment or buyout. At the end of the negotiation process, "IOUs would continue to have discretion to accept or reject any resulting proposal based upon existing AB 57 portfolio management standards," and any "accepted offers will be subject

---

[4] *Id*. at 85-87.

[5] December 11, 2019 Presentation at 26.

to approval by the CPUC."[6] Therefore, any contract above market price should be included for consideration for removal from an IOU's portfolio in the RFI.

Fluctuation in the MPB is not a reason to remove any contract that is above market cost from consideration in the RFI. POC acknowledges that the wholesale market prices vary and are currently correlated with natural gas prices.[7] However, as renewable energy and energy storage become a larger part of the overall market, the price of renewables and storage will increasingly affect and soon dictate wholesale market prices. And the price of those resources are steadily declining. Between 2007 and 2018, the cost of RPS contracts decreased from approximately $180/kWh to $40/kWh.[8] That trend is continuing. Los Angeles Department of Water and Power (LADWP) signed a contract in 2019 for solar at $19.97/MWh, or $33/MWh when including storage.[9] LADWP's electricity price for solar plus storage falls significantly below the approximately $50/MWh average wholesale electricity price in 2018.[10]

---

[6] December 11, 2019 Presentation at 25.

[7] Between 2010 and 2018, the total annual wholesale cost of electricity varied between $50/MWh and $30/MWh. Department of Market Monitoring, 2018 Annual Report on Market Issues and Performance at 3 (May 2019) (Figure E.1), http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf; Department of Market Monitoring, 2014 Annual Report on Market Issues and Performance, at 4 (June 2015) (Figure E.1), http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf

[8] Cal. Public Utilities Commission, 2019 Padilla Report at 7 (May 2019) (Figure 3), https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2019/Padilla%20Report%202019%20-%20Final(1).pdf

[9] Request for Official Notice, Exhibit C, Excerpts of Attachment to Report from City Administrative Officer (Sept. 11, 2019), http://clkrep.lacity.org/onlinedocs/2019/19-1081_misc_4_09-20-2019.pdf.

[10] Department of Market Monitoring, 2018 Annual Report on Market Issues and Performance at 3 (Figure E.1).

With renewable and storage resources comprising an increasing share of the state's resources, they will exert a downward pressure on the wholesale market price and MPB. Accordingly, the MPB will not simply fluctuate up and down in the future. As wholesale market prices are decoupled from gas prices, they will mirror the downward trajectory of the renewables and storage market. Therefore, it is inappropriate to exclude any contracts above 100% of the MPB from the RFI process.

III. IOUs should terminate all contracts above the market price benchmark whenever legally possible.

In the event of a material default by a counterparty to a contract above the MPB, the Commission should require IOUs to terminate that contract. The co-chairs propose to require that all IOUs' Energy Resource Recovery Account (ERRA) compliance filings include reports of any material events of default, termination rights, and resulting actions.[11] POC supports this reporting requirement because it increases transparency of the IOUs' activities to divest their portfolios of high-priced contracts. Yet simply requiring reporting does not go far enough.

In addition to the reporting requirement, the Commission should require IOUs to terminate high-priced contracts in the PCIA portfolio in the event of material default or the ability to exercise a termination right. The only exception to this rule should be if an IOU is able to reach an agreement with the counterparty that would reduce the PCIA by a greater amount than would be achieved through termination.

[11] December 11, 2019 Presentation at 28.

IV. The voluntary allocation and market offer proposal should include POC's automatic enforcement and shareholder responsibility mechanisms.

The co-chairs' allocation and auction proposal should include automatic enforcement mechanisms to ensure IOUs immediately implement the portfolio optimization mechanisms adopted by the Commission.

The co-chairs' voluntary allocation mechanism requires IOUs to regularly provide to other load serving entities (LSEs) the quantity of their forecast and actual allocation of resource attributes. IOUs that do not provide these forecasts and actual allocation amounts on a schedule approved by the Commission should provide bill credits to bundled and unbundled customers. These bill credits should be given by IOU shareholders to customers within 60 days of the missed deadline, without the need for any Commission action.

IOUs should administer the voluntary allocation mechanism in a timely, efficient, fair, and transparent manner because they control access to information about the PCIA resources paid for by all customers. POC's automatic enforcement and shareholder responsibility mechanism aligns the interest of shareholders in avoiding penalties with the interests of all customers in an efficient and timely administration of the allocation mechanism. It also compensates customers when they are harmed by an IOU's mismanagement of the allocation mechanism. These bill credits are modeled on the customer service guarantees that shareholders provide customers when an IOU misses a deadline that has important ramifications for the customer, including missed appointment times and inaccurate bills.[12] Bill credits are appropriate

---

[12] Dkt. A.02-05-004, Southern California Edison 2003 General Rate Case, D. 04-07-022, Opinion on Base Rate Revenue Requirement and Other Phase 1 Issues, at 164 (July 8, 2004) (approving $30 bill credits with the justification that "a self-enforcing mechanism that can create a significant incentive for SCE to meet the adopted standards"); *id*. at 126 (shareholders responsible for bill credits); Pacific Gas & Electric Co., Service Guarantees, https://www.pge.com/en_US/residential/customer-service/other-services/service-guarantees.page

in this case because an IOU that fails to provide a forecast or actual allocation on schedule impedes the LSEs' ability to efficiently manage their portfolios; this has important ramifications for customers.

For example, IOUs that publish renewable portfolio standard (RPS) or greenhouse gas-free (GHG-free) allocations that underallocate attributes to unbundled customers should provide a $30 credit to unbundled customers' bills. Similarly, IOUs that publish RPS or GHG-free allocations that underallocate resources to bundled load customers should provide a $30 credit to bundled customers' bills.[13] Based on information provided by the co-chairs to POC, it does not appear that IOUs will publish allocations of resource adequacy (RA) attributes, therefore this proposal does not discuss RA allocations.

Next, the co-chairs' market offer mechanism requires IOUs to regularly administer auctions for certain attributes from PCIA resources. The efficient administration of these solicitations is an essential part of the co-chairs' proposal to reduce the PCIA rate. Due to the IOUs' track record in administering PCIA resources, POC is concerned that IOUs may not efficiently and accurately administer these auctions.[14] POC's proposal aligns shareholders'

(accessed Dec. 19, 2019) ($30 bill credits approved in 1999 and 2003 General Rate Case; shareholders responsible for bill credits).

[13] At the December 11, 2019 workshop, IOUs expressed concern about the inability to contest the automatic bill credits included in POC's proposal. POC does not oppose Commission review of the bill credits after they are issued.

[14] For example, Peninsula Clean Energy sought to purchase local RA for the 2019 reliability year. It responded to all of PG&E's requests for offers and made other efforts to procure capacity, but was unable to procure enough local RA to meet its need. Notice of Ex Parte Meeting of the California Community Choice Assn., at 2 (May 13, 2019). The needed capacity was subsequently offered by PG&E to the market only after the compliance deadline for LSEs to obtain RA for 2019. *Id*. This is one example of IOUs unreasonably administering their resource portfolios.

interest in avoiding penalties with customers' interest in efficient administration of these auctions.

POC proposes that if an IOU that does not complete its auction on the schedule set by the Commission, within 60 days of the missed deadline the IOU's shareholders should provide a $30 bill credit to the unbundled customers on whose behalf the action was to be conducted.

Further, POC proposes that an IOU withholding resources that an LSE requested be auctioned provide bill credits to the unbundled customers on whose behalf the auction was to be conducted. The total shareholder cost would be the highest auction bid multiped by the quantity of attributes not auctioned. If no auction took place, the total shareholder cost would be the most recent MPB for that attribute multiped by the quantity of attributes not auctioned. This amount would be distributed to unbundled customers on whose behalf the auction was to be conducted through bill credits.

POC is concerned about the ability of the working group to develop an effective shareholder responsibility proposal in the time available before the working group's final report is due on January 30, 2020. POC has presented the only shareholder responsibility proposal to the working group to date. If the co-chairs are not able to develop a proposal that results in an effective shareholder responsibility mechanism, they should submit their completed proposals for Commission consideration and request additional time for the working group to develop an effective proposal to address this critical issue.

V. POC supports the adoption of a voluntary allocation and market offer framework that includes several changes from the co-chairs' proposal, including market offers for local RA and GHG-free attributes.

A. A spring market offer will maximize the value of RA attributes for customers.

POC supports the co-chairs' proposal to hold a second RA market offer and auction in the spring of each year.[15] Under this proposal, LSEs have an opportunity to decline their allocation for the following year in the first quarter. A portion of any declined allocations are then made available in the spring market offer and auction. POC supports this proposal because it provides an opportunity to maximize the value of RA attributes for LSEs that know in advance that they plan to decline their allocations. Further, POC appreciates that this proposal allows LSEs maximum flexibility because they are not required to decline allocations in the first quarter and retain the right to decline their full allocation in the fall.

B. A cap on long-term RPS sales is unnecessary, but if implemented should be accompanied by regular reports on its impact.

At the December 11, 2019 workshop, the co-chairs proposed that the Energy Division publish an annual report "summarizing results of the auctions and potential impact of the cap on long-term sales on realized value."[16] While POC would prefer that the auction not contain a cap, if one is implemented POC supports this reporting requirement.

POC disagrees with the co-chairs' proposal to cap the quantity of long-term sales made in the RPS auction. To capture the most value for the RPS product, IOUs should always accept the highest price offered for the sale of RPS regardless of contract length. A large quantity of renewable resources will enter the market as California moves towards its statewide renewable

[15] December 11, 2019 Presentation at 13.

[16] December 11, 2019 Presentation at 13.

energy goals and more Community Choice Aggregators ("CCAs") with aggressive renewable energy mandates form. With this influx of new renewable resources—built with the advantage of today's prices that are lower than the cost of the older RPS resources[17] in the PCIA portfolio—the market price of RPS products is likely to drop precipitously in the next several years. Therefore, the PCIA auction mechanism should capture the highest value of RPS products available in the near term. POC believes that the ability to secure long-term revenues for RPS resources in the near term is more important than ensuring that allocations from the PCIA portfolio are available to customers who switch between LSE providers.

C. POC continues to support the co-chairs' local RA allocation proposal when paired with an auction.

The co-chairs offer a proposal that allocates local RA to LSEs. POC supports the premise of this proposal as a short-term portfolio optimization mechanism if it is paired with an auction. Below, POC discusses its proposed change to the local RA proposal's treatment of penalties.

First, POC disagrees with the co-chairs' proposal that

> any CAISO costs or penalties required for, or imposed as a result of, local RA resource outages will receive full cost-recovery through the PCIA . . . except for any costs disallowed through the IOU's ERRA proceeding.[18]

Penalties should not automatically be eligible for recovery in the PCIA. IOUs maintain a responsibility to prudently manage their PCIA-eligible resources to avoid any penalties. Therefore, it is unreasonable to presume that these penalties are customers' responsibility.

---

[17] CA Public Utilities Commission, 2019 Padilla Report, at 7 (May 1, 2019) (figure 3), https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2019/Padilla%20Report%202019%20-%20Final(1).pdf.

[18] R.17-06-026, Detailed RA Sales Process Strawman, Local RA Allocation, GHG-Free Allocation & Voluntary Allocation Process: Workshop No. 2 Presentation, at 25 (July 25, 2019) ("July 25, 2019 Presentation").

Instead, shareholders should take financial responsibility for any penalties, as they are responsible for managing their PCIA-eligible resources in a way that avoids the imposition of penalties.[19] Should shareholders seek to impose the cost of penalties on departing load customers, an IOU should be required to file an application, in a docket distinct from the ERRA proceeding, showing why these costs should be customers' responsibility. Put simply, penalties that result from imprudent management of resources should be shareholders' responsibility.

D. POC continues to support the co-chairs' GHG-free allocation proposal when paired with an auction.

The co-chairs offer a proposal that allocates a proportional share of GHG-free attributes to other LSEs.[20] This proposal makes sense because GHG-free attributes have a value, and all customers who pay the PCIA are entitled to a portion of that value.[21] POC supports this proposal as a short-term portfolio optimization solution if it is paired with an auction. POC also suggests two clarifications to improve the co-chairs' GHG-free proposal.

GHG-free resources include nuclear and hydroelectric resources. Some CCAs are not authorized to purchase or use nuclear resources, therefore any GHG-free allocation proposal should include a mechanism allowing LSEs to opt out of receiving GHG-free attributes from nuclear resources. The co-chairs disagree on what to do with the declined GHG-free attributes from nuclear resources. Commercial Energy would auction the declined attributes and credit the auction proceeds to the LSEs declining the attributes.[22] California Community Choice

---

[19] If IOUs cannot manage their resources without incurring penalties, or do not want the obligation of resource management, they should sell those resources.

[20] July 25, 2019 Presentation at 26-30.

[21] *See* July 25, 2019 Presentation at 27 (a "credit within [the] Power Content Label, Clean Net Short, or other similar reporting mechanisms").

[22] *See* July 25, 2019 Presentation at 28; *Id*. at 33.

Association (CalCCA) and SCE would similarly allow LSEs to decline receiving GHG-free attributes from nuclear resources, but instead of auctioning off the declined attributes, they "would be reallocated automatically amongst LSEs participating in the allocation."[23]

POC continues to support Commercial Energy's proposal because it provides the LSE declining an allocation of GHG-free attributes the financial value of the attributes to which it was entitled. In contrast, CalCCA and SCE would allocate the value of attributes paid for by one LSE to the customers of another LSE without compensation. CalCCA and SCE offer no support for their proposal to shift the value of attributes from one LSE to another without compensation. This aspect of the proposal offered by CalCCA and SCE should be rejected because it violates the requirements of Public Utilities Code sections 365.2 and 366.3 to prevent cost shifting.

VI. Conclusion

POC thanks the co-chairs for the opportunity to submit these comments.

[23] July 25, 2019 Presentation at 28

DATED: December 20, 2019

SHUTE, MIHALY & WEINBERGER LLP

By: /s/ Yochanan Zakai

ELLISON FOLK
YOCHANAN ZAKAI*
396 Hayes Street
San Francisco, California 94102
(415) 552-7272
Folk@smwlaw.com
yzakai@smwlaw.com

Attorneys for Protect Our Communities Foundation

DATED: December 20, 2019

PROTECT OUR COMMUNITIES FOUNDATION

By: /s/ Tyson Siegele

TYSON SIEGELE
Energy Analyst
Protect Our Communities Foundation
4452 Park Blvd., #202
San Diego, California 92116
(917) 771-2222
tyson@protectourcommunities.org

1192351.7

* Mr. Zakai is a member of the Oregon State Bar; he is not a member of the State Bar of California.

A Sempra Energy utility®

January 6, 2020

INFORMAL COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY REGARDING PCIA WORKING GROUP 3 FOURTH WORKSHOP (R.17-06-026)

SDG&E appreciates this opportunity to provide comments regarding the fourth workshop held by Working Group 3 ("WG 3") in Phase 2 of the Power Charge Indifference Adjustment ("PCIA") proceeding. In Decision (D.) 18-10-019, the Commission established WG 3 to consider the structure, processes, and rules governing portfolio optimization to be adopted by the Commission in order to address excess resources in utility portfolios.

SDG&E supports the recommendation offered by Pacific Gas and Electric Company ("PG&E") to include examples and timelines in the workgroup report. SDG&E also recommends that the WG 3 co-leads schedule an additional workshop to review the open issues that remain in WG 3.

SDG&E's notes that optimization and cost reduction of investor owned utilities' ("IOU") respective resource portfolios must consider both short- and long-term timeframes. It is therefore crucial to ensure that the portfolio optimization measures applied in one timeframe do not interfere with optimization efforts undertaken within another timeframe. During the fourth WG 3 workshop, the co-leads suggested that short term allocations, including allocations of long-term Renewable Portfolio Standard ("RPS") resources, is a contingent product. In other words, even though a load-serving entity ("LSE") elects to accept its share of the allocation, the IOU may optimize its portfolio in the future and LSEs should not be dependent on such future allocations. SDG&E supports this proposal because it provides options for the IOUs to optimize their portfolios without being restricted due to the allocation process.

SDG&E is concerned, however, that the proposed allocation process does not fully address the scope of WG 3, creates inefficiency and could create additional burden for bundled service customers after the IOU has optimized (*i.e.*, "right-sized") its long-term portfolio. First, the allocation process does not reduce the total above-market costs of the utilities' PCIA-eligible portfolios because it shares the total costs with the relevant vintage customers. Second, if an IOU has optimized its portfolio but is then required to allocate portfolio resources to LSE(s), it would be faced with the prospect of going back to the market to re-procure certain products needed to meet compliance obligations. There are only three "markets" that offer such products:

the IOUs must procure products from the primary bilateral market, trade with other LSEs in the secondary market in the case of System and Flexible RA capacity, or participate in its own voluntary allocation market offer ("VAMO") process when another LSE elects to not take its allocation. Finally, if the allocation process results in the IOUs still having surplus capacity, it is unclear whether the IOUs would be required to make such surplus available through the market offer process by electing to not take its surplus capacity. It is not clear whether the VAMO process is superior to the excess sales framework developed during the Working Group 1 process. It would be helpful to parties for the WG 3 co-leads to provide clear examples of how the VAMO process works, compared to the excess sales framework. Given that there will be advantages and disadvantages to both frameworks, SDG&E recommends that each IOU be allowed to utilize either the excess sales framework <u>or</u> the proposed allocation framework, depending upon which best fits its portfolio and best serves the LSEs that also serve customers in the IOU's service territory.

The most recent proposal changes the definition of the market price benchmark ("MPB"). In the Working Group 1 decision (D.19-10-001), the MPB for the various products was limited to certain transactions executed up to 3 years prior to the compliance or delivery year. The most recent proposal would eliminate this limitation and the MPB would be calculated based on all contracts executed for a particular delivery term. The co-chairs' rationale for this proposed modification is that "[l]ong-term sales can create the potential for cost shifts with Rate Making Option 2, when using the Market Price Benchmark approach, as adopted in Track 1, to set price that parties taking allocations should pay."[1] SDG&E disagrees with this conclusion for the reasons set forth below.

First, the allocation framework is not interchangeable with the excess sales framework developed in Working Group 1. This is because the excess sales approach differentiates the various products into three categories: compliance, sold and unsold. The MPB is then used to determine the amount of above-market cost paid by all customers in the vintage and the costs up to the MPB paid by bundled service customers for the compliance portfolio. The MPB does not play a role in the cost allocation for sold and unsold products paid by all customers in the vintage as the sales price sets a specific MPB for each specific sold product while unsold products are valued at zero dollars. Under the allocation framework, these three categories are restructured into a single category as all LSEs in a vintage share in all the attributes and total net costs[2] within that vintage. Thus, the MPB would effectively serve little purpose other than determining the amount of cost paid directly by customers while the remaining "above-market" amount is paid to the IOU by the LSE. The LSE would then have the option to determine how it would recover such costs from its customers. Additionally, it is unclear if the proposal would result in different PCIA rates for different LSEs depending on who takes or does not take allocations because the proposed MPB may be different than the price of a sale in the market offer. In such an instance, who is responsible to make up the difference? Is it the customer or the LSE? SDG&E

[1] WG 3, Workshop #4 Presentation, Slide 21.

[2] LSEs share in the total costs net of California Independent System Operator ("CAISO") market revenues.

recommends that the co-leads provide an example in the workshop report to allow parties to better understand the proposal.

Second, it is suggested that including long-term sales in the MPB would offer other LSEs taking the allocations the benefit of having locked in such "long-term" pricing. This makes little sense because as explained above, regardless of the MPB value, an LSE taking an allocation will be taking on its share of the total contract cost (at-market and above-market). A market transaction of a different resource would only impact the amount of cost customers are directly billed by the IOU and the residual amount directly paid to the IOU by the LSE taking the allocation.

Finally, transactions entered into prior to year N-2 may not be reflective of the actual market. It is unclear how the co-leads' proposal to calculate the MPB using weighted average of long-term contracts transacted prior to year N-2 would be implemented. SDG&E recommends that the co-leads include formulas and examples to allow parties to better understand the proposal.

During the fourth workshop, the co-leads discussed various IOU portfolio management and optimization activities. The co-leads proposed a request for information ("RFI") process for contract assignments and buy-outs. The RFI process would connect sellers with LSEs or other market participants with generators under contract with the IOU at that time. The proposed RFI process would also allow generators to propose contract buy-outs. Finally, the process would be held annually for the first two years, after which the Commission would consider whether the process should be modified or continued biannually.

SDG&E is encouraged that the co-leads have proposed a process to facilitate portfolio optimization of the IOUs' portfolios. The IOUs should be actively seeking opportunities to right-size their portfolios and reduce costs for customers. SDG&E believes that a voluntary RFI process could be a start to meeting that goal. SDG&E provides the following comments regarding the co-leads' proposal:

The RFI process should not be the only means for the IOUs to optimize their portfolios and should not be mandatory. The market fluctuates daily, and the right opportunities do not wait for an RFI process to begin – flexibility is crucial to ensuring that ratepayers receive the greatest value from portfolio optimization activities. If the IOUs are permitted to initiate portfolio optimization only during an RFI timeline, any opportunities that fall outside of this timeframe may be lost, which directly undermines the IOU's ability to optimize its portfolio. SDG&E recommends that the IOUs be permitted to optimize their portfolios anytime throughout the calendar year in lieu of a formalized, mandatory and prescriptive RFI process.

SDG&E notes that today LSEs may collaborate and negotiate with IOUs for contract assignments because the IOU is a party to the existing contract and must take an active role in understanding the resulting impact to PCIA for all other customers. SDG&E also notes that the proposal to require the IOU to submit any contract assignment agreements to the Commission is consistent with existing practice. This process ensures the terms of the new agreement are in the best interest of customers.

SDG&E does not support newly-proposed exclusions that would prevent assignment of contracts. As a threshold matter, there is no valid rationale for excluding contracts priced above 115% of the MPB or resulting in IOU RPS compliance issue from portfolio optimization activities. All opportunities for optimizing IOU portfolios and reducing costs to customers should be on the table – including portfolio optimization involving contracts with above-market costs. Imposing artificial restraints will hinder rather than facilitate the IOUs' optimization and cost-reduction efforts. Additionally, the MPB is only applicable to certain attributes of a power purchase agreement ("PPA") and therefore would not be relevant as a basis for comparing the cost of the entire contract. It would be improper to compare contract costs to a MPB that reflects only a subset of the products in the PPA.

Contracts, either through contract assignment or buy-outs, may require a one-time payment. Such payments may impact the PABA account such that the change in the PCIA rate is greater than the current PCIA rate change cap of 0.5 cents per kilowatt hour. SDG&E recommends that any payments that results from portfolio optimization be exempted from the PCIA cap calculation in order to avert a significant under collection in PABA that would shift risks to bundled service customers.

SDG&E notes that securitization may be another option for IOU portfolio optimization. Securitization was suggested by parties in Phase 1 of the PCIA proceeding. While not discussed during the WG 3 workshops, securitization should not be excluded from the available options for portfolio optimization. SDG&E requests that the co-leads include a reference to securitization in the workshop report as a potential additional optimization opportunity that may be available in the future.

SDG&E disagrees with the proposal by Protect Our Communities Foundation ("POC") to effectively establish a rebuttable presumption imposing automatic penalties on IOUs for any alleged mismanagement of the portfolio. The default assumption of IOU mismanagement is improper; POC's proposal is neither reasonable nor constructive. Not all "event of default" or "terminations" are in the best interest of the customers. POC's proposal would in essence require the IOU to defend its actions as compared to theoretical outcomes that may have been unavailable to the IOU.

In addition, the proposal to submit a new report on cost savings from such activities is duplicative, unnecessary, and inequitable. The IOUs already report portfolio management activities through various Commission processes. All amendments are discussed with the IOUs' procurement review group ("PRG"), as required by the Commission. To the extent contracts are modified due to active portfolio optimization, the IOUs submit such contract amendments to the Commission for approval or through the IOUs' quarterly compliance reports ("QCRs"), which are reviewed by the Commission. The resulting financial impacts are detailed in the IOUs' energy resource recovery account ("ERRA") filings. These filings are reviewed and scrutinized by parties in open and transparent proceedings. SDG&E does not believe additional reporting, which takes away time from active portfolio management, is necessary. For the reasons stated above, SDG&E does not support POC's proposal for additional reporting.

***

大成 DENTONS

John W. Leslie
Partner

john.leslie@dentons.com
D +1 619 699 2536

Dentons US LLP
4655 Executive Drive
Suite 700
San Diego, CA 92121
United States

dentons.com

MEMORANDUM

To: Service List in R.17-06-026 (PCIA)

From: Shell Energy North America (US), L.P. ("Shell Energy")

Date: December 20, 2019

Subject: Informal Comments on the Working Group 3 Issues Raised at the December 11 Workshop

Consistent with the schedule discussed at the December 11, 2019 workshop on Working Group 3 issues, Shell Energy provides informal comments on two of the proposals advanced in the workshop. First, Shell Energy opposes the proposal for a mandatory allocation of each IOU's local RA capacity to all LSEs. Second, Shell Energy comments on the proposal addressing the treatment of RPS supplies that are "bundled" and allocated by the IOUs on a long-term (minimum 10-year) basis.

1. Mandatory Allocation of an IOU's Local RA Capacity: The Working Group 3 proposal includes a provision (page 8 of the PowerPoint presentation) that requires each IOU to allocate all of its local RA capacity to all LSEs (through a CAM-like mechanism) based on load share. Under this approach, an IOU would retain its bundled sales customers' proportionate share of the local RA capacity. The remainder of the capacity would be allocated to other LSEs based on an LSE-specific load forecast.

Shell Energy opposes this proposal, for at least three reasons. First, the Commission should be reducing, not increasing, the reach - the breadth - of the CAM. Any expansion of the CAM - or a CAM-like mechanism - discourages LSEs from purchasing their own RA resources. This has become evident as a result of the IOUs' procurement of energy storage (and allocation of the cost through the CAM), because the "automatic limiter" has reduced - to zero - an ESP and CCA's obligation to procure energy storage to meet the energy storage target. Applying a CAM approach to the IOUs' existing local capacity will discourage ESPs and CCAs from developing and procuring their own local RA capacity, as well.

Second, an ESP or a CCA that already has procured its own local RA capacity, including procurement on a long-term basis, should not be forced to accept an allocation of the IOU's local RA capacity. The proposed approach would likely result in the ESP or CCA holding excess local RA capacity. This, in turn, would require the over-resourced LSE to re-sell its excess local RA capacity to mitigate stranded costs. This approach would cause the LSE to bear stranded costs disproportionate to the stranded costs borne by other LSEs. The proposed approach has the potential to place an LSE in a competitively disadvantaged position if the LSE has obtained its own local RA capacity.

Third, it is not enough that the proposal provides that an LSE may "trade" its excess local RA capacity to mitigate its stranded costs. Resales of an LSE's excess local RA capacity may or may not enable the LSE to offset its stranded costs. An LSE should not be required to take the market price risk of additional local RA capacity (and the associated cost) foisted upon it by the IOU.

Based on these concerns, Shell Energy opposes a mandatory allocation, to all LSEs, of an IOU's local RA capacity. Shell Energy supports, instead, an approach through which an IOU holds an annual (and more frequent or for longer terms, as appropriate) voluntary bilateral sale or auction process to allocate excess local RA capacity, similar to the proposed annual voluntary allocation of PCIA-eligible RPS energy and system and flexible RA capacity.

2. Treatment of the Long-Term Attribute of RPS Supplies that are Allocated (on a Voluntary Basis) by the IOUs: Shell Energy supports the proposal that provides for preservation of the long-term attribute of an IOU's RPS supplies when the IOU sells a portfolio of RPS energy or RECs from its long-term (10-year) RPS supply contracts. As long as the LSE purchases this portfolio for a term of at least 10 years, the LSE should receive the benefit of the long-term (10-year) attribute for the entire portfolio.

In this connection, the acquiring LSE should be able to claim the long-term attribute for an IOU's "long-term" RPS portfolio even if some of the contracts in the portfolio have terms less than 10 years. As long as the acquiring LSE has made a minimum 10-year procurement commitment, the LSE should be able to claim this RPS energy (and RECs) as eligible to meet the minimum 10-year contract requirement.

This approach is supported by D.17-06-026 (June 29, 2017). In that Decision, the Commission stated as follows: "[I]f the original RPS procurement contract is 10 years or more in duration, the contract will be considered long term for all subsequent extensions. If a short-term RPS procurement contract is amended by an extension of at least 10 continuous years in duration, the contract will be considered a long-term contract from the date of that amendment through the life of the contract." Decision at p. 20. The Decision also stated the following with respect to "repackaged" long-term arrangements: "The use of repackaged long-term contracts is reasonable in the context of the new SB 350 requirements. Such contracts may be used to meet the LT [long-term] requirement, so long as they are truly long term, i.e., the retail seller's contract for its repackaged share of the generation has a duration of at least 10 years." Decision at p. 21.

On this basis, Shell Energy supports the Working Group 3 proposal, including the provision (page 12 of the PowerPoint) that states: "To receive long-term credit, the longest RPS contract in their vintage must have a remaining term of at least 10 years." Only one contract in the IOU's long term portfolio must have a remaining term of at least 10 years in order for the acquiring LSE to be able to claim the long-term attribute for the purchased RPS energy and RECs.

Shell Energy looks forward to further discussion regarding these and other Working Group 3 issues.

Respectfully submitted,

John W. Leslie

Attorneys for Shell Energy North America (US), L.P.

US_Active\113895151\V-1

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 2 WORKING GROUP #3 WORKSHOP #4

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Matthew Freedman, Staff Attorney
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org

December 20, 2019

COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 2 WORKING GROUP #3 WORKSHOP #4

TURN offers the following comments on certain issues reviewed in the 4th workshop of Working Group 3 (WG 3) on December 11, regarding portfolio optimization and cost reduction, and allocation and auction. Citations refer to slides presented at the 4th workshop (Presentation).

Allocations of long-term contract compliance attributes

The Presentation proposes to allow any LSE to accept their entire allocation of RPS-eligible procurement within the IOU portfolio (subject to adjustments for IOU portfolio optimization activities). Assuming that there is at least one contract within the allocation with a remaining forward duration of at least 10 years, the working group proposes that the entire allocated portfolio quantity count towards the long-term contract compliance obligations established under Public Utilities Code §399.13(b).[1]

Based on a review of the proposal, TURN is concerned that some of the individual contracts within the portfolio will not have forward durations of at least 10 years at the time the LSE elects to receive the allocation. TURN requested data from each IOU on the prospective durations of RPS-eligible contracts that would be included in portfolio allocations. PG&E and SCE responded to this request just as these comments were due. TURN has not been able to adequately review or analyze this data. Without more opportunity to review comprehensive data from all IOUs, it is difficult to assess what portion of the portfolio would be comprised of contracts that have less than 10 years remaining if an LSE were to take its allocation beginning in 2021.

While TURN recognizes that each LSE would make a commitment of not less than 10 years its entire allocation, that allocation is comprised of a large number of individual contracts. Some of those contracts would not qualify as long-term if they were

[1] Presentation, page 12.

remarketed in a forward sale. This fact complicates any assessment as to whether the quantities should qualify as long-term when bundled within a package of deals that, taken together, runs more than 10 years in duration.

In 2014 the Commission declined to authorize cost recovery for "long-term" contracts proposed by PG&E that would have provided 90% of total deliveries in the first year and spread the remaining deliveries over the following nine years.[2] That rejection was based in large part on TURN's critique that PG&E attempted to circumvent the long-term contracting requirement by entering into a "10-year" contract that was functionally a short-term arrangement.[3] While the proposed PCIA portfolio allocation proposal would not result in the same unbalanced delivery schedule included in PG&E contracts rejected by the Commission, it does raise questions about the types of arrangements that would satisfy the RPS long-term contract requirement.

Due to the unique circumstances associated with the PCIA portfolio allocation, the Working Group should clarify that the requested treatment of long-term contract attributes under this proposal would only apply to PCIA portfolio allocation. To avoid the potential for abuse, the Commission must clarify that other market participants should not expect to receive RPS long-term contract credit for bilateral arrangements that include a mix of short and long-term commitments.

Any voluntary allocation of RPS or GHG-free resources must be structured as a forward sale of a bundled product

The proposed voluntary allocation of RPS and GHG-free resources would allow LSEs to accept an assignment of a share of the IOU portfolio. In prior comments, TURN identified the need for the WG3 proposal to conform to existing conventions relating to

[2] PG&E Advice Letters 4299-E, 4300-E, 4301-E; The Commission rejected Draft Resolution E-4649 that would have approved the contracts.

[3] TURN/CUE protest of PG&E AL 4299-E, 4300-E, 4301-E, October 30, 2013; TURN comments on Draft Resolution E-4649, March 27, 2014.

the forward sale of bundled products. The Presentation does not explicitly conform the allocation to the forward sale requirements.[4]

In prior comments, TURN expressed concern about any initiative to create a new class of unbundled GHG-free attributes that can be traded separately from the electricity generated by the associated units. Any such scheme would run afoul of both the Clean System Power methodology used in the Integrated Resource Planning (IRP) process and the California Energy Commission's Power Source Disclosure Program (PSDP). Neither program allows LSEs to acquire unbundled attributes that can be used to offset portfolio GHG emissions for reporting purposes. The final proposal should explicitly state that all allocated products would be conveyed on a forward basis and include attributes bundled with the associated electricity from the underlying generator to ensure that there is no conflict with the IRP and PSDP protocols.

TURN appreciates the opportunity to submit these comments.

Respectfully submitted,

MATTHEW FREEDMAN

___________/S/____________

Matthew Freedman
Staff Attorney
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org

Dated: December 20, 2019

---

[4] Presentation slides 8, 11.

Appendix F

EXTERNAL ENGAGEMENT

External Engagement

The WG 3 Co-Chairs provided parties to R.17-06-026 with various means of involvement and engaged in a number of conversations. Below the Co-Chairs summarize the methods used to engage with and seek feedback from parties to the proceeding.

A. Workshops

As required by the Phase 2 Scoping Memo, the WG 3 Co-Chairs held four workshops to brief parties to the proceeding about the Co-Chairs' proposals for portfolio optimization, active management of utility portfolios, transition to new standards, and shareholder responsibility for portfolio mismanagement. Below the Co-Chairs summarize each of the workshops held by WG 3.

1. First Workshop – Strawman for Excess Sales

The First Workshop was held on April 29, 2019 from 1:30 – 3:30 PM at the Pacific Energy Center in San Francisco, CA. Approximately 47 parties attended in person and 39 parties participated remotely via WebEx. The First Workshop focused primarily on the straw proposal for identifying and offering for sale any "excess" RA and RPS resources in the IOUs' portfolios. Commercial Energy also discussed its concept for the VAAC. The First Workshop presentation is attached to the First Progress Report of WG 3.

Parties were asked to serve written comments in response to the topics presented at the First Workshop by May 10, 2019. Informal comments were received from 10 parties: Alliance for Retail Energy Markets ("AReM"), California Large Energy Consumers Association ("CLECA"), City of San Diego, NextEra Energy, PG&E, Protect Our Communities Foundation ("POC"), Public Advocates Office ("Cal PA"), San Jose Clean Energy ("SJCE"), Shell Energy ("Shell"), and The Utilities Consumers' Action Network ("UCAN"). The informal comments received in response to the First Workshop are attached to the First Progress Report of WG 3.

2. Second Workshop – System and Flex RA Excess Sales Proposal; Local RA Allocations; GHG-Free Allocations; and Voluntary Allocation and Auction Clearinghouse Proposal

The Co-Chairs held their Second Workshop at SCE's Energy Center in Irwindale, CA on July 25, 2019. The workshop was attended by approximately 27 people, with 22 participating via Skype. The Second Workshop began with a discussion of informal stakeholder feedback from the First Workshop and focused primarily on the following proposals: (1) Excess RA Sales Strawman for System and Flex RA, (2) Local RA Allocation Approach, (3) GHG-Free Allocation Approach, and (4) Commercial's VAAC Strawman. The Second Workshop presentation is attached to the Second Progress Report of WG 3.

The Co-Chairs invited informal comments following the Second Workshop, and six parties provided comments: AReM, Direct Access Customer Coalition ("DACC"), PG&E, POC, Cal PA, and UCAN. The informal comments are attached to the Second Progress Report of WG 3. The Co-Chairs elected to submit a response which is also attached to the Second Progress Report.

3. Third Workshop – RPS and System and Flex RA Voluntary Allocation & Market Offer Proposals

The Co-Chairs' Third Workshop was held on October 17, 2019 at the Commission's Auditorium in San Francisco, CA with approximately 35 people attending in-person, and another 15 via Skype. The Third Workshop began with a recap of the positions presented at the Second Workshop, along with several updates to refine the Local RA and GHG-free energy allocation proposals. The Co-Chair panel introduced the concept of the VAMO framework for System and Flex RA and RPS energy. Finally, the Co-Chairs presented two alternative frameworks for how ratemaking could be modified to accommodate the VAMO frameworks. The Third Workshop presentation is attached as Appendix A.

As with previous workshops, the Co-Chairs sought informal comments. Comments were received from eight parties: AReM, American Wind Energy Association of California ("AWEA") jointly with the Large-Scale Solar Association ("LSA"), DACC, PG&E, POC, San Diego Gas & Electric Company ("SDG&E"), SJCE, and TURN. The informal comments received in response to the Third Workshop are attached as Appendix B.

4. **Fourth Workshop – Refinement of Issue 1 Proposals; Issues 2-4**

The final, Fourth Workshop was held on December 11, 2019 at the Commission's Auditorium in San Francisco, CA. About 20 people attended in person and another 15 via Skype. The Fourth Workshop commenced with a brief recap of the previously articulated positions and provided updates to certain aspects of the RPS energy, GHG-free energy, and System and Flex RA proposals to simplify the proposals and accommodate stakeholder feedback. Following this discussion on the WG 3 Issue 1 topics, the Co-Chairs proceeded to discuss Issues 2 through 4.

Regarding Issue 2, the Co-Chairs presented on the existing framework for IOU portfolio optimization activities, with a consensus view that the IOUs should continue performing such activities. The Co-Chairs then presented a new proposal in which the IOUs would canvas their portfolios to gauge interest in doing a contract assignment with a third-party and/or terminations, which could include proposals to buyout contracts, with the intent of reducing the overall PCIA rate. For Issue 3, the Co-Chairs identified no major transition requirements that had not already been presented in other workshops. Finally, for Issue 4, the Co-Chairs proposed no changes to the existing shareholder responsibility framework, but CalCCA presented their proposal that additional reporting should be required in the ERRA Review of Operations application to report cost savings related to portfolio optimization activities and any material events of default, including whether any termination rights presented themselves and any actions taken with respect thereto. The Fourth Workshop presentation is attached as Appendix D.

The Co-Chairs requested informal comments by December 20, 2019. Comments were received from nine parties: AReM, Coalition of California Utility Employees ("CUE"), Cal PA, NextEra Energy, PG&E, POC, SDG&E, Shell, and TURN. The informal comments received in response to the Fourth Workshop are attached as Appendix E.

B. **Additional Engagement**

In addition to the Workshops, the Co-Chairs sought to provide information to and receive feedback from stakeholders through a variety of means. The Co-Chairs summarize their engagement with other parties below.

1. <u>Informal Comments</u>

Following each of the four workshops, the Co-Chairs sought the feedback and perspectives of stakeholders to the WG 3 process via informal comments submitted to the proceeding's service list. The informal comments proved valuable for the Co-Chairs, as it became evident where there was broad alignment for or against specific proposals put forth by the Co-Chairs, and where perspectives might differ among the third parties. The Co-Chairs sought to be responsive to parties' comments and used the feedback to inform their respective positions and achieve alignment where the Co-Chairs may have previously differed.

Following the Third Workshop, the Co-Chairs also sought feedback prospectively from the stakeholders to the proceeding. The Co-Chairs had identified that there would not be much time remaining to explore Issues 2 through 4 prior to the Fourth Workshop and had not identified any material topics to date. Thus, the Co-Chairs solicited input from the stakeholders at the Third Workshop to proactively submit any proposals they might have relating to Issues 2 through 4 for consideration by WG 3. The informal comments received on Issues 2 to 4 are attached as Appendix C.

2. <u>SharePoint Site</u>

In response to informal comments submitted following the Second Workshop, the Co-Chairs established a public SharePoint site to facilitate greater communication and transparency with the stakeholders participating in the WG 3 process. On September 5, 2019, SCE sent an email to the R.17-06-026 service list notifying parties of the publication of the WG 3 SharePoint site, which was hosted by SCE. A second email was distributed through SharePoint, granting access to members of the service list to the site. Materials on the SharePoint site include: (1) the Phase 2 Scoping Ruling, (2) the four WG 3 workshop presentations, (3) a video recording of the Second Workshop, (4) parties' informal comments to the four WG 3 workshops and the Co-

Chairs' request for proposals regarding Issues 2 through 4, (5) the two WG 3 progress reports, (6) the Procurement Process Reference Guide, (7) various WG 3 meeting agendas, and (8) a WG 3 draft project plan. The materials on the SharePoint site were updated as new materials became available, or as material changes unfolded with regards to the WG 3 project plan.

3. Direct Engagement with Stakeholders

In addition to the efforts the Co-Chairs undertook to prepare for and engage with stakeholders in the public workshops, the Co-Chairs also engaged in various discussions directly with key stakeholders in the WG 3 process. The Co-Chairs found this engagement to be very useful for soliciting feedback from third parties, exploring parties' concerns, and identifying alternative paths forward, as necessary.

a) Community Choice Aggregators

Acting simultaneously as one of the Co-Chairs and as a representative of the diverse group of CCA parties, CalCCA was intimately involved in seeking regular and frequent feedback from the many CCAs it represents. CalCCA held weekly meetings with representatives from the individual CCAs during which it presented the latest points of discussion among the Co-Chairs, sought feedback and proposals from its constituents, and sought consensus on positions to advocate for among the Co-Chairs. On a periodic basis, CalCCA briefed its board, composed of representatives of the cities and communities that its CCAs serve, to receive approval to accept certain positions on behalf of all of the members. Despite various differing points of view, CalCCA was able to identify consensus proposals amongst the various CCA parties, while representing their diverse interests.

b) Investor-Owned Utilities

SCE was designated the IOU Co-Chair within the Phase 2 Scoping Memo. The IOUs held calls at least twice a week throughout Phase 2 of the PCIA proceeding to discuss the proposals developed by the Co-Chairs and any cross-over issues with the ERRA, IRP, and the RA proceedings. Additionally, the IOUs' officers were briefed weekly on key updates and proposals requiring decisions by management to move forward. In addition to these multiple weekly calls, the IOUs also met several times in-person to conduct deep dives into the materials of each of the Working Groups. Typically, these sessions were held prior to workshops in order to ensure consistent understanding of the positions being advocated for, alignment on those positions, and to discuss next steps.

c) Other Load-Serving Entities

Commercial Energy generally represented its own interests in the PCIA case and WG 3, and it believes that those interests mirror the voice of its customers. However, in the interest of facilitating a broader discussion, Commercial held occasional calls and communicated by email with other LSEs, notably Direct Access ("DA") providers and suppliers, including Shell, AReM, and DACC, to discuss proposals and concepts developed by the Co-Chairs in WG 3. Commercial has not attempted to create a single consensus position among these LSEs out of concerns that a party (possibly the IOUs or the CCAs) might raise a claim of restraint of trade. Neither of those parties or their constituents face the same risk as ESPs and their customers. These calls were intended to increase parties' understanding of the specific issues other LSEs have raised and how WG 3 might address them. On more than one occasion, the other LSEs could not agree on specific features in the joint proposal(s) of the WG 3 Co-Chairs and have provided comments to that effect. Similarly, Commercial voiced the concerns raised by other LSEs, but was not always able to find a middle ground with SCE and/or CalCCA.

d) Protect Our Communities

In their informal comments regarding the Second Workshop, POC and UCAN identified concerns with the amount of transparency being provided by the Co-Chairs regarding the overall WG 3 process. POC sought to be included in the WG 3 Co-Chair weekly meetings but the Co-Chairs decided that given the substantial progress made to date and the detailed background needed to understand how consensus was achieved on each of the proposals, it would be unwieldy to add parties who have not been part of these detailed discussions. In an effort to be responsive to the concerns raised by POC regarding transparency, the Co-Chairs established a

SharePoint site to which the Co-Chairs published meeting agendas and a project plan laying out the proposed scope and timeline for the remainder of the WG 3 process.

Following the Third Workshop, POC provided informal comments proposing (1) a sunset of the PCIA within 5 years of each customer vintage's departure, (2) the prioritization of full resource removal from IOUs' portfolios, and (3) that the IOUs should be subject to automatic penalties for failing to adhere to the established timelines and requirements in administering the final PCIA WG 3 process, as ruled upon by the Commission. POC explained its proposals in more detail to the Co-Chairs during an hour-long phone call on November 19, 2019. The Co-Chairs jointly provided feedback as to the challenges and impacts associated with the proposals.

POC also spoke to its proposals at the Fourth Workshop and expressed interest in extending the time for the WG 3 process to continue discussions around appropriate shareholder responsibility within the PCIA process.

e) <u>The Utility Reform Network</u>

In its informal comments to the Third Workshop, TURN expressed concerns over SCE's proposed treatment of long-term RPS attributes, and urged the conveyance of RPS and GHG-free energy on a forward basis to comply with existing statutory requirements. The Co-Chairs held a conference call with TURN on November 15, 2019 to discuss the proposed mechanics related to an allocation and sale of RPS and preserving the long-term attributes. TURN expressed concern over short-term allocation decisions conveying long-term benefits. The conversation with TURN was beneficial for the Co-Chairs to understand concerns related to preservation of long-term attributes. Accordingly, the Co-Chairs presented a consensus, modified proposal for the treatment of long-term RPS attributes at the Fourth Workshop, based in part upon the feedback received from TURN.

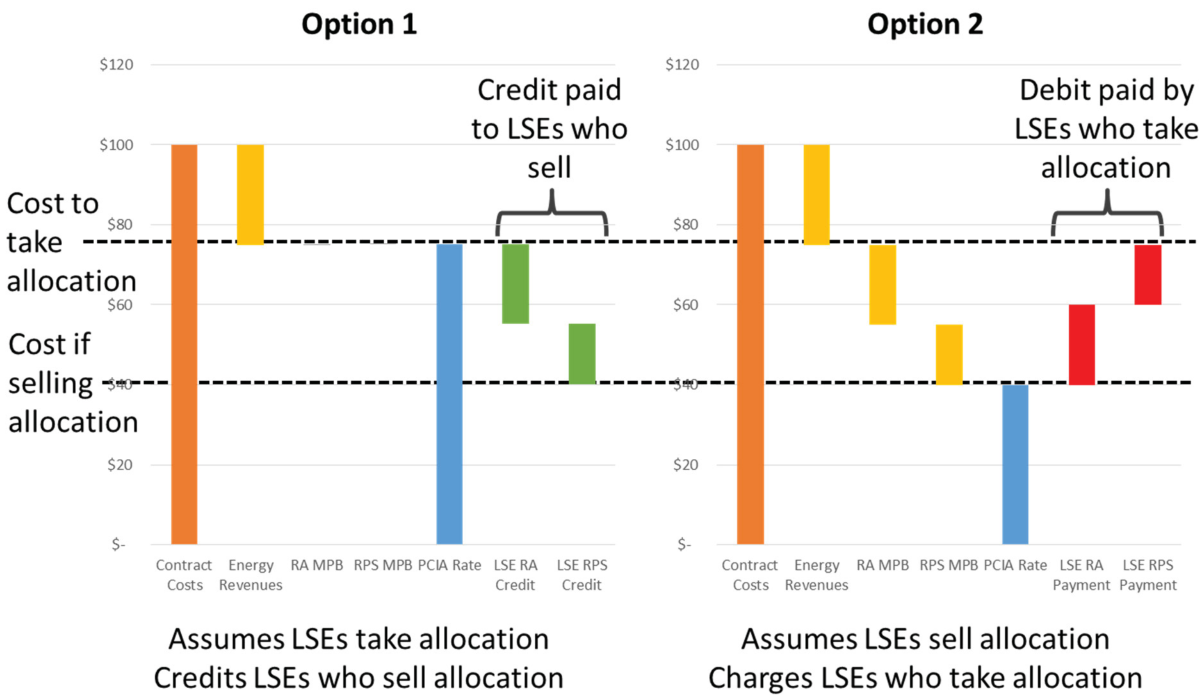
f) <u>California Public Utilities Commission's Energy Division</u>

Following the Third Workshop, the assigned ED staffers (Dina Mackin and Sasha Cole) reached out to the Co-Chairs to inquire whether a meeting might be possible to walk them through the proposals put forth within WG 3. On November 18, 2019, the Co-Chairs met in person with Dina Mackin and Sasha Cole at SCE's offices in San Francisco, CA. The Co-Chairs walked them through the Second and Third Workshop presentations, addressing questions, providing additional background, and receiving feedback on the process and proposals.

Appendix G

COMPARISON OF RATEMAKING APPROACHES

COMPARISON OF RATEMAKING APPROACHES



Appendix H

END-TO-END WG 3 ALLOCATION AND MARKET OFFER EXAMPLE

End-to-End WG 3 Allocation and Market Offer Example

This Appendix provides an end-to-end example of an illustrative IOU's PCIA-eligible portfolio that is made available for allocation among the IOU and four other PCIA-eligible LSEs. This example illustrates how each of the WG 3 proposals for Local RA, System and Flex RA, RPS energy, and GHG-free energy work, including the determination of vintaged peak- (MW) and annual- (MWh) load shares, allocations, re-allocations, ability to count attributes towards IRP, availability of attributes for the Market Offer, selection of offers, Market Offer revenue allocation, impact upon rates, and LSEs' total cost responsibility. The following narrative serves as a guide to understand what takes place within each calculation and to provide additional context around how the results in each table are to be interpreted.

This Excel workbook demonstrates only the mechanism for determining the impact of the first year's allocation elections for each product type. This workbook does not account for changes to allocation positions that would occur in the real world due to variations in resource's NQC or EFC values, portfolio optimization activities undertaken by the IOUs, contract management activities, resource production variability, changes in LSEs' load shares from year to year, regulatory changes, etc. Further, this workbook has several simplifications embedded for easier understanding. For example, the Flex RA product is not modeled, as it would follow the same process as System RA. The spring System RA Market Offer process is not modeled as it would follow the same methodology as the fall Market Offer process, and since there are no changes in position, there would not be much added value in modeling a second Market Offer process. Forecasted coincident peak loads are identified only as the annual peak load, rather than each month's coincident peak load. No true-up of the volumes and product MPBs is performed at year end to account for the actual payments LSEs taking allocations would need to make. These simplifications are called out throughout the following narrative to illustrate where additional complexity would otherwise arise.

For reference, in the Excel workbook, blue text represents hard-coded values, green text represents values inserted from another table within the workbook, and black text represent calculated values. Certain cells are shaded in green or in red to indicate that the calculations are working correctly or incorrectly, respectively, to check that the workbook has been properly programmed.

Table 1. LSE Assumptions

Table 1 presents the assumptions for each of the LSEs within the model IOU's service territory. Column B identifies the vintage corresponding to the LSEs' customers' departure dates. If an LSE were to have more than one vintage of customer departure, each vintage that the LSE serves could be viewed as an independent LSE for purposes of this example. Column C lists the illustrative annual load assumption for each LSE in GWh/yr. Column D lists the illustrative peak load assumption for each LSE in MW. Columns E through I reflect the illustrative elections that these modeled LSEs make with regard to each product type, with 100% reflecting an election to take 100% of the eligible allocation share, and 0% reflecting an election to decline all of the eligible allocation share. The RPS energy and System RA (and Flex RA – although this product is not modeled, as it would follow the same process as System RA) products permit LSEs to elect any 10% increment between 0% and 100%. Additionally, within the RPS elections, LSEs may elect to take a short-term allocation, a long-term allocation, or decline their election. Column E reflects how much of their eligible RPS allocation each LSE elects to accept as a long-term allocation. Column F reflects the LSEs' short-term allocation elections. The difference between 100% and the sum of the short-term and long-term allocation elections reflects the amount each LSE elects to decline from their RPS allocation.

Table 2. LSEs' Vintaged Annual Load Shares

Table 2 illustrates the methodology used for determining an LSE's vintaged annual (MWh) load share. Each row corresponds to a specific LSE and each column corresponds to a specific PCIA vintage. Within the table, each LSE's annual load is listed for each contract vintage in which it is eligible to participate, based upon its customers' departure date from the

IOU. For example, LSE A's customers departed in 2009, so LSE A is eligible to participate in the CTC-Eligible and 2004-2009 vintages only. LSE B's customers departed in 2014, so it is eligible for all PCIA vintages prior to 2014. The LSEs' loads for each vintage are summed in Row 11 and provide the basis for calculating each LSE's share of the total vintage load.

Table 3. **LSEs' Vintaged Annual Load Share Percentages**

Table 3 translates Table 2 into percentages of annual vintage load. Each LSE's load for each vintage is divided by the total eligible LSE load within that vintage (from Row 11) to calculate the LSE's vintaged annual load share. These LSE-specific vintaged annual load shares will be used to allocate the RPS and GHG-free energy.

Table 4. **LSEs' Vintaged Coincident Peak Load Shares**

Table 4 is similar to Table 2, but is used to calculate LSEs' vintaged coincident peak-(MW) load shares. As with Table 2, the LSEs' peak loads are mapped to each contract vintage in which the LSE is eligible to participate, based upon its customers' departure date. Row 11 calculates the total coincident peak load of all the LSEs eligible for the vintage. For the allocations of System and Flex RA, the forecasted, vintaged, monthly, coincident peak-load shares will be used, as per the existing RA and CAM processes. However, in this example, for simplification purposes, only the forecasted, vintaged, *annual*, coincident peak-load shares are modeled. For allocations of Local RA, the forecasted, vintaged, annual, coincident peak-load shares would be used for the CPUC showing, but for CAISO the forecasted, vintaged, monthly, coincident peak-load shares would be used.

Table 5. **LSEs' Vintaged Coincident Peak Load Share Percentages**

Table 5 is similar to Table 3, as it translates Table 4 into percentages of coincident peak load. Each LSE's peak-load for each vintage is divided by the total eligible LSE peak-load within that vintage (from Row 11) to calculate each LSE's vintaged, coincident peak-load share. These LSE-specific vintaged, coincident peak-load shares will be used to allocate the PCIA-eligible Local, System, and Flexible RA attributes.

Table 6. **Model IOU Portfolio**

Table 6 presents an illustrative IOU portfolio of PCIA-eligible resources. These portfolio resources will be used throughout this end-to-end example to illustrate how the resources' attributes are allocated among the PCIA-eligible LSEs. Column A provides an identifier for each contract, which will be used throughout the example to reference back to specific contracts or UOG resources. Column B identifies the vintage corresponding to each contract or UOG resource. Column C identifies whether the contract or resource is "Bundled" or "RA-only." "Bundled" contracts are contracts in which the IOU receives energy and capacity benefits, in addition to any other resource attributes, whereas "RA-only" contracts provide the IOU with only RA capacity. Columns D through H identify the specific attributes that the IOU receives under each contract, with "Yes" meaning the IOU receives that column's attribute and "No" meaning the IOU does not receive the attribute. In column H, for GHG-free energy, the type of resource is identified as either "Large Hydro[electric]" or "Nuclear." RPS resources provide GHG-free energy benefits, but those benefits are allocated through the RPS VAMO process, rather than the GHG-free energy voluntary allocation process, and are thus identified as "No" in the GHG-free energy column. Columns I and J identify the price paid by the IOU for the contract or UOG resource according to either a bundled PPA price (in $/MWh) (in Column I) or an RA price (in $/kW-month) (in Column J). Column K corresponds to the contracts' or UOG resources' online dates. Note that the online dates may be several years after the date indicated by the vintage, as new generation resources may take a few years to come online after contract execution. Contract execution date is the milestone used for determining the contract's vintage. Column L indicates the term of the contract or expected life of the UOG resource, in years. Column M is calculated by adding the term of the contract or life of UOG resource to the online date to determine the expected contract end date or decommissioning date for UOG resources. Column N indicates the technology of the generating resource, which is used to determine whether the resource is considered RPS-eligible or falls into the Large Hydro or Nuclear GHG-free energy pools. Column O indicates the resources' installed AC capacity (in MW), which is used to determine the expected annual energy production (in GWh) in Column P and the amount of RA capacity available from the resource in Table 33, based upon the technology of the resource in Column N and the resources' Effective Load Carrying Capacity ("ELCC") in Table 32.

Table 7. <u>GHG-Free, Large Hydro Position by Contract</u>

Table 7 shows the first step for how the GHG-free energy allocations work. Each large hydroelectric resource that is identified from Column H on Table 6 has its PCIA vintage identified from Column B on Table 6. The expected annual energy production from Column P on Table 6 is mapped to the delivery years identified in Row 4 based upon the Online Date in Column K and Termination Date in Column M, both on Table 6. For simplification purposes, each contract is assumed to last for the full delivery year. Row 24 calculates the total energy production from GHG-free energy resources in each delivery year.

Table 8. <u>GHG-Free, Large Hydro Position by Vintage</u>

Table 8 sums the GHG-free energy production from each delivery year for each contract vintage identified in Column B of Table 7. This identifies the vintage-specific GHG-free energy attributes available for allocation to each LSE on the basis of their customers' departure vintages.

Table 9. <u>GHG-Free, Large Hydro Allocation Eligibility</u>

Table 9 demonstrates the portion of the IOU's PCIA-eligible GHG-free energy portfolio that each LSE would be eligible to receive in each delivery year based upon the prompt year's (*i.e.,* 2023's) forecasted, vintaged, annual load shares. This can also be seen as the amount of GHG-free energy procurement credit that each LSE would be able to count towards its IRP Clean Net Short procurement targets, however in implementation the IRP may elect to distinguish LSEs' forecasted annual load shares for each year, rather than applying just the prompt year's forecast as in this simplified example.

The calculation of each LSE's eligible share is performed by multiplying the IOU's portfolio generation in each vintage in each delivery year from Table 8 by each LSE's forecasted vintaged annual load share from Table 3, and then summing across all vintages to determine each

LSE's total share of the GHG-free energy product. In the Excel file, this calculation is simplified by using a SUMPRODUCT function.

For reference, the SUMPRODUCT function works by multiplying the individual components of each array that correspond to the same position in the array and then summing all of the products together. For example, Cell B5 (i.e., the IOU's 2023 GHG-free energy allocation share of the PCIA-eligible portfolio) is calculated according to the following formula:

*= [Vintaged portfolio generation] * [LSE vintaged* annual *load share]*

*= [920, 0, 0, …, 0] * [66%, 66%, 76%, …, 100%]*

= 920 x 66% + 0 x 66% + 0 x 76% + … + 0 x 100%

= 605 GWh

Table 10. **Large Hydro Allocations Accepted**

Table 10 evaluates the actual deliveries of GHG-free energy that each LSE elects for the prompt year (*i.e.,* 2023). The allocation election that each LSE makes, from Table 1, is multiplied by the share of the GHG-free energy production that the LSE is eligible for in 2023, from Table 9. In the example, LSE B elected to decline its allocation, and thus there is an amount of unallocated large hydroelectric energy identified in Row 22.

Table 11. **Large Hydro Re-Allocation**

Table 11 determines how to re-allocate the unallocated GHG-free energy that was declined by LSE B. Column F calculates the re-allocation percentage, which is equal to the volumes of large hydroelectric energy that each LSE elected to accept divided by the total volume of allocated large hydroelectric energy. This is an equivalent percentage to the LSE's forecasted, vintaged annual load relative to the forecasted, vintaged annual load of all other LSEs that elected to take their allocations. Column G calculates how much large hydroelectric energy should be allocated to each LSE by multiplying the volume of unallocated large hydroelectric energy by each LSE's re-allocation percentage.

Table 12. <u>Total Large Hydro Allocations</u>

Table 12 summarizes how much large hydroelectric energy each LSE would be expected to receive based upon the forecasted generation and their forecasted annual load shares. It sums the initially allocated volumes with the re-allocated volumes to determine the total volume of GHG-free, large hydroelectric energy for each LSE.

Table 13. <u>GHG-Free, Nuclear Position by Contract</u>

Table 13 commences the assessment of how much GHG-free, nuclear energy each LSE will be forecasted to receive based upon their allocation elections. Table 13 functions in a similar manner to Table 7 by identifying the expected annual energy production from all nuclear resources in the IOU's portfolio by contract for the term of the contract or life of the UOG asset. The resource's vintage is identified to facilitate aggregation by vintage in Table 14. As with Table 7, the example is simplified to assume that the resource is available for the entire delivery year.

Table 14. <u>GHG-Free, Nuclear Position by Vintage</u>

Table 14 sums all of the nuclear energy production in each year by vintage. This table functions in the same fashion as Table 8.

Table 15. <u>GHG-Free, Nuclear Allocation Eligibility</u>

Table 15 calculates each LSE's eligible share of the nuclear energy production based upon the prompt year's (*i.e.,* 2023's) forecasted, vintaged, annual load shares. As with Table 9, these eligible delivery amounts would be equivalent to the amount of GHG-free, nuclear energy production that each LSE may claim in IRP for CNS purposes. The calculation functions in the same way as in Table 9.

Table 16. <u>Nuclear Allocations Accepted</u>

Table 16 determines the initial nuclear energy allocation volumes that each LSE would receive based upon their allocation elections, as identified in Table 1. The nuclear allocation election is multiplied by the forecasted nuclear generation for 2023 in Table 15. In this example, LSEs B, C, and D elected to decline their nuclear allocations, so there is unallocated nuclear energy.

Table 17. Nuclear Re-Allocations

Table 17 calculates how the unallocated nuclear energy is to be re-allocated among the LSEs choosing to take their allocation of nuclear energy. As with Table 11, each LSE's allocated volume of nuclear energy is divided by the total allocated volume of nuclear energy to determine the re-allocation percentage. This re-allocation percentage for each LSE is multiplied by the total unallocated nuclear energy volume to determine how much nuclear energy is re-allocated to each LSE.

Table 18. Total Nuclear Allocation

Table 18 summarizes how much GHG-free, nuclear energy each LSE would be forecasted to receive based upon its allocation elections and the decisions of other LSEs around their allocation elections. The initial allocation volumes are summed with the re-allocated volumes for each LSE to determine each LSE's forecasted total nuclear energy allocation.

Table 19. RPS Energy Position by Contract

Like Tables 7 and 13, Table 19 calculates how much RPS energy is available in each delivery year from each contract, and identifies the contracts' vintages so that the forecasted RPS generation can be summed by vintage in Table 20. Again, the example is simplified to assume that the resource is available for the entire delivery year.

Table 20. RPS Energy Position by Vintage

Like Tables 8 and 14, Table 20 sums the RPS energy available in each delivery year by contract vintage. This will be used in Table 21 to determine each LSE's eligible share of the PCIA-eligible RPS portfolio on the basis of their customers' departure date.

Table 21. RPS Energy Allocation Eligibility

Like Tables 9 and 15, Table 21 determines the eligible share of the IOU's PCIA-eligible RPS energy position that each LSE would be forecasted to receive based upon the prompt year's (*i.e.,* 2023's) forecasted, vintaged, annual load shares. The calculations function the same in Table 21 as in Tables 9 and 15.

These forecasted, eligible allocations of RPS energy would not necessarily be the volumes that each LSE would be able to count in IRP, however. RPS is a bit different from other products for IRP treatment, as the results of the Market Offer must be evaluated to determine how much IRP credit each LSE may receive, as long-term sales may remove PCIA-eligible RPS energy from the portfolio for allocation to the LSEs that had declined a portion of their eligible allocation shares.

Table 22. <u>RPS Energy Long-Term Allocations Accepted</u>

Table 22 evaluates the forecasted volumes of RPS energy that each LSE has elected to accept as a long-term allocation. As Table 21 has determined each LSE's total eligibility for allocations, Table 22 simply multiplies each LSE's eligible RPS energy allocation volume in each delivery year by that LSE's long-term allocation election percentage from Table 1.

Table 23. <u>RPS Energy Short-Term Allocations Accepted</u>

Table 23 evaluates the forecasted volumes of RPS energy that each LSE has elected to accept as a short-term allocation, i.e., just for the prompt year, 2023. Table 23 multiplies each LSE's total eligible RPS energy allocation volumes from Table 21 by that LSE's short-term RPS allocation election percentage from Table 1 to determine the volumes that LSE would be expected to receive as a short-term allocation in 2023.

Table 24. <u>Total RPS Energy Allocations Accepted</u>

Table 24 determines the total RPS energy volumes that each LSE would be expected to receive at the RPS MPB in each delivery year by summing the long-term and short-term allocation volumes from Tables 22 and 23, respectively, for each LSE.

Table 25. <u>RPS Allocation Payments</u>

Table 25 calculates the estimated allocation payments that each LSE would owe for its purchase of the allocated RPS energy volumes in 2023. Table 25 multiplies the 2023 forecasted RPS energy allocation volumes from Table 24 by the forecasted RPS MPB from Table 53 to calculate the forecasted allocation payments. It is important to note that the LSEs' payments would be subject to the actual RPS energy deliveries realized throughout the delivery year, and would be trued up according to the actual MPB near the end of the delivery year.

Table 26. Distribution of RPS Allocation Payments Across Vintages

Table 26 determines how the revenues realized from LSEs' RPS energy allocation purchases in 2023 are to be distributed to the PABA vintaged sub-accounts. The total RPS energy expected to be produced in 2023 within each vintage is multiplied by the percentage of each vintage that is to be allocated and is further multiplied by the forecasted RPS MPB for 2023 to determine the forecasted total RPS allocation payments within each vintage for 2023. The percentage of each vintage to be allocated is determined by multiplying each LSE's total allocation election percentage (i.e., the sum of short- and long-term allocation election percentages) by each LSE's forecasted annual load share, and summing the resulting LSE-specific percentage for each vintage to determine the total (i.e., across all LSEs) percentage of the RPS energy generation to be allocated within each vintage. These steps for determining the percentage of each vintage to be allocated are simplified in the Excel workbook through the use of the SUMPRODUCT function described in the write-up for Table 9.

Table 27. RPS Allocations Declined

To determine the volumes to be offered in the RPS Market Offer process, Table 27 first determines the forecasted total unallocated RPS energy volumes for 2023, based upon LSEs' elections. To calculate this amount, each LSE's total RPS allocation for 2023, from Table 24, is subtracted from each LSE's eligible RPS allocation volume for 2023, from Table 21. The total volume of RPS energy that is declined across all LSEs, in Row 10, will be the amount of RPS energy that is available for sale in the Market Offer for delivery in 2023.

Table 28. RPS Energy Available for Long Term Market Offer

Table 28 calculates how much RPS energy is available for sale in the Market Offer under long-term (i.e., 10 or more years) contracts. Within each Market Offer, the IOU will offer for sale up to 35% of each LSE's declined allocation, up to a maximum of 35% of each LSE's eligible allocation share. To calculate this, Table 28 calculates the lesser of (i) the volumes declined by each LSE in 2023, in Table 27, and (ii) each LSE's eligible allocation share for each delivery year, in Table 21. This value is then multiplied by the 35% long-term sales cap to calculate the maximum RPS energy volume (attributable to each LSE) that may be sold in each delivery year under a long-term sale. The volumes that may be sold long-term that are attributable to each LSE are then summed to determine the maximum volume that may be offered for sale long-term for each delivery year within the Market Offer, as demonstrated in Row 23. The maximum volumes that may be offered for sale short-term are identified in Row 24, for the prompt year (2023) only. Note that the long-term volumes may be sold as short-term, so the long-term volume is a subset of the short-term volume, and the two volume numbers should not be added together.

Table 29. <u>RPS Market Offer Bids and Selections</u>

Table 29 demonstrates the bids received in a mock RPS Market Offer process and demonstrates which bids would have been selected, and what the resulting revenues would be. Each bid is numbered in Column A. Each bid is assigned a mock volume (expressed as a percentage of the RPS energy production available for sale), price (in $/MWh), and term (expressed in years, which may be one year or 10 or more years in length). The bids are ordered from highest to lowest price in order to facilitate the bid selection.

To commence the bid selection process, Column E translates each bid's volume from Column B into a GWh volume based upon whether the bid is short-term (i.e. 1 year in length) or long-term (i.e., 10 or more years in length) and multiplying the bid's volume percentage by the total generation that is available for sale in the short-term (Row 24) or long-term (Row 23) from Table 28. Column F next identifies the volumes that are desired to be purchased within each long-term bid, which are then summed in sequential order from highest to lowest price in Column G to calculate the cumulative long-term bid volumes, up to the maximum long-term volumes available for sale in 2023 from Table 28, Row 23. Similarly, Column H calculates the total cumulative volume bid, in sequential order from highest to lowest offer, including both the long- and short-term contracts, up to the maximum volume available for short-term sale as identified in Table 28, Row 24. Both Columns G and H are needed to ensure that the maximum volume that is available for sale as either long-term or short-term is not exceeded in offer selection.

Column I next calculates whether each bid is "Selected," "Partially Selected," or "Not Selected." A bid is selected if the difference in the total cumulative volume (in Column H) between the current bid and the previous, higher-priced, bid is equal to the current bid's volume. A bid is not selected if the difference in the Total Cumulative Volume in Column H does not increase, indicating that all volumes available for sale in the Market Offer have been sold. A bid is partially selected, meaning only a portion of the bid volumes are selected, based upon the maximum volume remaining available in the Market Offer. Bids that are partially selected are identified by having the incremental increase in the Total Cumulative Volume (Column H) from the previous bid not be equal to the volume desired in the bid. Column J calculates the volume of RPS energy sold under each bid and ensures that the total does not exceed the volumes available within the Market Offer. Column K translates the volumes sold back into percentages, which would be used for contracting purposes under slice-of-generation contracts, which would be identified as short- or long-term pursuant to Column L. The forecasted revenues from each bid that is selected or partially selected are calculated in Column M by multiplying the bid price by the selected volumes. All of the bids' forecasted revenues are summed to determine the total expected revenues from the Market Offer process, which is divided by the volume offered for sale to determine the weighted average price realized in the Market Offer from accepted bids. If unsold volumes existed, those unsold volumes would be factored in to determine the weighted average price realized for revenue allocation purposes in Table 30. Additionally, those unsold volumes of RPS energy would need to be re-allocated among all PCIA-eligible LSEs at $0/MWh on the basis of the LSEs' forecasted, vintaged, annual-load shares. As there are no unsold RPS volumes in this example, and for simplicity purposes, this step is not demonstrated in this example, but the process would follow the example set forth in Tables 48 through 50 for System and Flex RA.

Table 30. <u>RPS Market Offer Revenue Allocation by Vintage</u>

Table 30 calculates how the revenues realized in the RPS Market Offer process are to be allocated across the PABA sub-accounts corresponding to each vintage. In Column B, the declined RPS energy volumes sourced from each vintage are calculated by multiplying each vintage's total expected PCIA-eligible RPS generation by the percentage of each vintage that is declined. The percentage of each vintage that is declined is calculated by first subtracting each LSE's allocation election percentage from 100%, to calculate each LSE's declined allocation election percentage. Second, this value is multiplied by the LSE's annual load share percentage for each vintage to determine the percentage of each vintage declined by each LSE. Third, these values are all summed to calculate the total percentage of each vintage that is declined. Within the Excel model, these three steps are combined into the SUMPRODUCT function, which functions as described in the description for Table 9, above.

The revenues ascribed to each vintage are calculated in Column C and are calculated by multiplying the declined volumes sourced from each vintage (in Column B) by the weighted average price realized in the RPS Market Offer (including unsold volumes) from Table 29.

Table 31. <u>RPS Market Offer Revenue by LSE</u>

While only relevant in the context of Ratemaking Option 1, which was considered but not pursued by the Co-Chairs and is shown for illustrative purposes in Tables 56 to 58, Table 31 calculates the RPS Market Offer revenues attributable to each LSE on the basis of their RPS energy allocation elections. Each LSE's declined RPS energy volumes are identified in Column B. In Column C, each LSE's declined RPS energy volumes from Column B are divided by the total declined RPS energy volumes and then multiplied by the total RPS energy revenues to determine each LSE's pro rata share of the RPS Market Offer revenues.

Table 32. <u>Source of Long-Term RPS Sales</u>

Table 32 identifies from which LSEs' eligible RPS energy allocation shares the long-term RPS energy sales are to be sourced from. The percentage of long-term sales sold in the Market Offer from Cell K17 on Table 29 is multiplied by the portion of each LSE's eligible allocation that is available for long-term sale in the Market Offer, based upon Table 28. The amount of long-term RPS energy sourced from each LSE is important as it informs how much IRP credit that LSE may receive and for ensuring that in future Market Offers that no more than 35% of that LSE's eligible allocation share is offered for sale through long-term contracts.

Table 33. <u>RPS Energy Available for IRP CNS Credit</u>

Table 33 identifies the amount of RPS energy that each LSE may count for IRP Clean Net Short credit. Each LSE's short-term and long-term sales are deducted from the eligible RPS energy allocation volumes to determine the credit that LSE may receive in IRP. Short-term sales will only impact the prompt year (2023 in this example), once they have been executed. Long-term sales will have a lasting impact to reduce the credit the LSE may receive in IRP, as the buyer of the long-term RPS energy in the Market Offer may count the RPS energy towards its IRP requirements.

Table 34. <u>Monthly Effective Load Carrying Capacity</u>

Table 34 demonstrates each technology's Effective Load Carrying Capacity ("ELCC") as identified by the CAISO for each calendar month in 2020. The technology-specific ELCC factors will be used to determine each bundled contract's NQC in Table 35.

Table 35. <u>Monthly Contract NQC Value</u>

Table 35 identifies the available NQC for each contract by month. The installed AC capacity for each contract, from Table 6, is multiplied by the relevant ELCC factor for that contract's technology for the relevant month from Table 34 to determine the NQC. The portfolio's NQC is determined in Row 25 by summing all of the contracts' NQC values in each month.

Table 36. <u>Local RA Position by Contract</u>

Table 36 calculates the monthly PCIA-eligible Local RA position by contract for the multi-year Local RA compliance period (*i.e.*, three years). Each contract that provides Local RA is identified by vintage in Column B, and has its NQC for each calendar month identified for the each month that the contract is active within the IOU's portfolio. The total PCIA-eligible Local RA position for each month is calculated in the bottom row of the table.

Table 37. <u>Local RA Position by Vintage</u>

Table 37 illustrates the PCIA-eligible Local RA position by vintage for the multi-year compliance period. Each month's Local RA position is summed by the contracts' PCIA vintages identified in Column B of Table 36.

Table 38. <u>Local RA Allocations</u>

Table 38 shows the Local RA volumes that each LSE will receive through its allocation, and that each LSE may use for IRP credit. Each LSE's forecasted, vintaged, coincident peak-load share for the prompt year, from Table 5, is multiplied by the monthly, vintaged Local RA positions identified on Table 37, and is summed across the vintages to determine the total Local RA volume that each LSE will receive in the allocation. This is performed in the Excel file through the use of the SUMPRODUCT function.

Note that while Table 38 shows the Local RA that would be shown for allocation in the 2022 RA compliance filing year for 2023-25, the Co-Chairs propose that in the first year of implementation in the 2022 RA compliance filing, LSEs would only have 2024 and 2025 Local RA positions allocated. In the 2023 RA compliance filing, LSEs would receive a full three year allocation for 2024 to 2026 showing years.

Additionally, in IRP, LSEs would receive credit for their forecasted share of their forecasted eligible Local RA share through the end of the term of the PCIA vintage, rather than just for the three year period shown in Table 38.

Table 39. <u>System RA Position by Contract</u>

Table 39 summarizes the System RA volumes provided by each contract that provides System RA, but not Local RA. Like Table 36, each contract that provides System RA is identified by vintage in Column B, and has its NQC for each calendar month identified for the each month that the contract is active within the IOU's portfolio over the next three years. The total PCIA-eligible System RA position for each month is calculated in the bottom row of the table. The Flexible RA position would similarly be identified for each contract that provides Flexible RA, but neither Local RA nor System RA.

Table 40. <u>System RA Position by Vintage</u>

Table 40 illustrates the PCIA-eligible System RA position by vintage for the next three years. Each month's System RA position is summed by the contracts' PCIA vintages identified in Column B of Table 39. Flexible RA would similarly be summed across the various contracts' vintages to identify each vintage's Flexible RA position for allocation.

Table 41. <u>System RA Allocation Eligibility</u>

Table 41 identifies the amount of System RA that each LSE would be eligible to receive as an allocation. Each LSE's forecasted, coincident peak-load share for each vintage is multiplied by the relevant vintage's System RA position for each month to determine the volume of System RA capacity that the LSE will receive from that vintage within that month. The LSE's shares of each vintage are all summed together for each month to determine the total position that each LSE would be eligible to receive in each month. This is modeled in Excel using the SUMPRODUCT function.

Again, while Table 41 only shows the three years of forward positions, LSEs would be able to claim their eligible allocation share of the PCIA-eligible System or Flexible RA through the end of their PCIA vintage's term.

Table 42. <u>System RA Allocations Accepted</u>

Table 42 identifies the System RA allocation volumes actually accepted for allocation by each LSE, based upon their allocation elections identified in Table 1. Each LSE's eligible

System RA volumes for each month in the prompt year are multiplied by the LSE's allocation election. LSEs may not make different percentage elections for each month. Only the prompt year (2023) is modeled, as LSEs only make elections and receive allocations for the prompt year. Row 11 calculates the difference between the total System RA position that was available for allocation and the sum of the LSE's allocated System RA volumes to determine how much System RA is available for sale in the Market Offer.

As this end-to-end example does not alter the positions within the IOU's portfolio throughout the course of the year, the example is being simplified to omit the spring Market Offer that System and Flex RA would be subject to in the Co-Chairs proposal. The process for determining the volumes to be sold in the spring Market Offer would be the same as shown in Table 42, but the LSEs' option to decline an allocation would be capped at 50% in the spring, to ensure that any changes to any LSE's vintaged, coincident peak-load share, change in System or Flex RA position due to portfolio optimization, or NQC or EFC updates, etc. would not inhibit the ability to fulfill any LSE's election for an allocation by selling too much System or Flex RA capacity in the spring Market Offer.

Table 43. **<u>Allocation Payments by LSE</u>**

Table 43 calculates the forecasted payment that each LSE accepting an allocation would need to pay for each month of the compliance year. The System RA volume allocated in each month to each LSE is multiplied by the forecasted System RA MPB to determine the expected payment for each month by each LSE. The amounts owed in each month are summed to determine the total owed by each LSE for the compliance year, subject to the true-up of the MPB at the end of the year.

Table 44. **<u>Distribution of System RA Allocation Payments Across Vintages</u>**

Table 44 determines how the revenues realized from LSEs' System RA allocation purchases in 2023 are to be distributed to the PABA vintaged sub-accounts. The total System RA available in each month within each vintage is multiplied by the percentage of each vintage that is to be allocated and is further multiplied by the forecasted System RA MPB for 2023 to determine the forecasted total System RA allocation payments for each month within each vintage for 2023. The percentage of each vintage to be allocated is determined by multiplying each LSE's System RA allocation election percentage by each LSE's forecasted coincident peak-load share of each vintage, and summing the resulting LSE-specific percentage for each vintage to determine the total (*i.e.,* across all LSEs) percentage of the System RA capacity to be allocated within each vintage for each month.

Table 45. <u>Declined System RA</u>

Table 45 identifies the System RA volumes declined by each LSE within each month, which will be pooled and made available for sale within the System RA Market Offer process.

Table 46. <u>System RA Market Offer Bids</u>

Table 46 illustrates the bids received within a mock Market Offer. The bids are assigned a bid number in Column A and each bid is provided an illustrative price (in $/kW-month) and term (identified according to the months marked with a 1). The revenue expected from each bid is calculated in Column P, and is equal to the product of the volume, the price, the number of months purchased, and whether the offer is selected or not (1 or 0, respectively, in Column Q).

To perform the Market Offer selections, Excel's Solver add-in is utilized to maximize the total revenues realized in the Market Offer process, identified in Cell P16. In Solver, Cells Q6:Q15 are to be changed to identify the maximum revenue. Table 47 is used in the calculation to ensure that the total System RA volumes sold in each month do not exceed the volumes available for sale, so Cells C35:N35 are constrained to be less than or equal to Cells C11:N11 in Table 45[1]. Finally, as the selections are binary in nature (either selected or not), an additional constraint is added that makes Cells Q6:Q15 equal a binary outcome (*i.e.*, 0 or 1). Solver is then run, potentially a few times, until the result stabilizes at a maximum revenue amount. The resulting bid selection set is reflected in Column Q, with a 1 indicating the bid was selected and a 0 reflecting that the bid was rejected.

---

[1] Note this must be manually updated each time Solver runs, since Solver does not save that the reference is on a different tab.

Table 47. System RA Volumes Sold in Market Offer

Table 47 is used within the Solver calculation for Table 44, and demonstrates the results of the Market Offer. Each bid within Table 46 has its volume multiplied by the 1 or 0 corresponding to whether the month is or is not included in the term and the 1 or 0 corresponding to whether the bid was selected or not in Column Q of Table 46. Row 35 sums the volumes sold from each month across all of the selected bids to determine how much capacity was sold in each month.

Table 48. Unsold System RA

Table 48 calculates the amount of System RA that remains unsold following the System RA Market Offer process. The total volume of System RA that is sold in in each month in the Market Offer from Table 47 is subtracted from the total declined volume of System RA in each month from Table 45 to calculate the unsold System RA in each month.

Table 49. Unsold System RA by Vintage

Table 49 distributes the unsold System RA across the PCIA vintages on the basis of the vintages from which the capacity was originally sourced. The monthly, vintaged RA position from Table 40 is multiplied by (i) the percentage of System RA that is declined within each vintage and (ii) the ratio of unsold System RA to declined System RA (*i.e.,* offered for sale) in each month.

Table 50. Unsold System RA Re-Allocation

Table 50 identifies how much of the unsold System RA is re-allocated to each of the PCIA-eligible LSEs. The unsold System RA is re-allocated across all PCIA-eligible LSEs on the basis of their forecasted, vintaged, peak-load share. Accordingly, each LSE's peak-load share is multiplied by the unsold System RA volume within each vintage, from Table 49, and is then summed across the vintages to determine that LSE's total re-allocation of System RA.

Table 51. **<u>Total System RA Allocations</u>**

Table 51 identifies the total amount of System RA that each LSE receives as an allocation, which is equal to the sum of the LSE's elected allocation share plus the unsold RA that is re-allocated to the LSEs.

Table 52. **<u>Market Offer Revenue Allocation across Vintages</u>**

Table 52 demonstrates the distribution of the System RA Market Offer revenues across the PABA vintaged sub-accounts. The monthly, vintaged RA position from Table 40 is multiplied by the percentage of System RA that is declined within each vintage and the weighted average price of all RA offered for sale (*i.e.*, the sold and unsold System RA volumes) to determine the revenues attributable to each vintage and each month.

Table 53. **<u>Market Offer Revenue Allocation by LSE</u>**

As with Table 31, Table 53 is only relevant in the context of Ratemaking Option 1, which was considered but not pursued by the Co-Chairs and is shown for illustrative purposes in Tables 56 to 58. Table 53 identifies the revenues from the System RA Market Offer that are attributable to each LSE based upon their elections to decline their allocations. The total volumes across all of the months in the compliance year are summed for each LSE and multiplied by the average price realized across all System RA offered for sale in the Market Offer process (*i.e.*, the sold and unsold volumes).

Table 54. **<u>Market Price Benchmark Assumptions</u>**

Table 54 identifies the forecasted Market Price Benchmarks for each product, which would be published in the IOU's ERRA Forecast Application for the prompt year. Each of these MPBs would be trued-up in the next year's IOU ERRA Forecast Application. In the case of System RA and RPS energy this true-up of the respective MPBs will require a true-up payment from the LSEs purchasing allocations. In the case of energy and ancillary services, the actual revenues realized will continue to require a true-up to be realized through PCIA rates.

Table 55. Costs and Energy Revenues by Contract

Table 55 demonstrates the expected annual contract cost, energy revenue, and net above market costs associated with each contract, which is to be used in Table 56 to calculate the costs and energy revenues associated with each vintage.

Table 56. Net Above Market Costs to be Recovered in PCIA Rates by Vintage

Table 56 illustrates the difference in cost recovery through PCIA rates paid by customers between the two ratemaking options considered by the Co-Chairs. Each vintage has its total contract and UOG costs identified in Column B and the total energy revenue reflected in Column C. The net above market cost for each vintage is reflected in Column D, and reflects the above market cost that would be recovered through PCIA rates under Ratemaking Option 1, wherein no value would be attributed to any of the resource attribute MPBs. The revenues realized from System and Flex RA allocations (Column E) and System and Flex RA Market Offer sales (Column F) and from RPS energy allocations (Column G) and RPS energy Market Offer sales (Column H) are identified for each vintage and are subtracted from the net above market costs for Ratemaking Option 1 to reflect the net above market costs to be recovered in PCIA rates under Ratemaking Option 2.

Table 57. Illustrative PCIA Rate Calculations

Table 57 demonstrates how the PCIA rates would be calculated for each vintage based upon the two different ratemaking options considered by the Co-Chairs. Each of the net above market costs corresponding to each of the ratemaking options is identified in Columns B and C, from Table 56. Additionally, the total vintaged load across all of the eligible LSEs in each vintage is identified in Column D. The incremental rate relating to each vintage is calculated for Ratemaking Option 1 in Column E and for Ratemaking Option 2 in Column F by dividing the net above market costs for each ratemaking option by the total vintaged load in Column D. The actual rate that would be charged to the customers under each of the ratemaking options is calculated in Columns G and H by summing each incremental rate sequentially.

Table 58. <u>Total Cost Responsibility – Ratemaking Option 1</u>

Table 58 demonstrates the net costs paid by customers and LSEs after accounting for the LSEs' share of revenues credited against the PCIA rates paid by their customers under Ratemaking Option 1. The revenues to be distributed from the IOU to each LSE for the sale of declined RA allocations in the Market Offer is identified from Table 53, and the revenues to be distributed to each LSE for the sale of declined RPS allocations is identified from Table 31. These revenues serve as credits to the LSE to reduce their customers' net payments for PCIA above market costs, as indicated in Column G.

Table 59. <u>Total Cost Responsibility – Ratemaking Option 2</u>

Table 59 demonstrates the total costs paid both by LSEs for the purchase of allocations and their customers for their payment of PCIA rates. The costs to be paid by each LSE for their RA allocations are identified from Table 43 and the costs for RPS energy allocations are identified from Table 25. These allocation payments are added to the LSEs' customers' PCIA rate payments to determine the net costs paid by each LSE and its customers.

Regardless of whether Ratemaking Option 1 or Option 2 is implemented, the net costs borne by customers is the same, as demonstrated by comparing the Net PCIA Cost Responsibility in Column G between Tables 58 and 59.

Table 1

LSE Assumptions

LSE	Vintage	Annual Load (GWh)	Peak Load (MW)	Allocation Elections (1 - Accept, 0 - Decline)				
				RPS Energy (Long-Term)	RPS Energy (Short-Term)	Nuclear Energy	GHG-Free Energy	System RA
IOU	2020	50,000	13,000	100%	0%	100%	100%	100%
A	2004-2009	10,000	2,500	0%	0%	100%	100%	0%
B	2014	3,000	800	0%	0%	0%	0%	50%
C	2018	1,000	300	70%	30%	0%	100%	0%
D	2018	12,000	3,500	50%	0%	0%	100%	80%

Table 2
LSE's Vintaged Annual Load Shares

		Annual Vintaged Loads (GWh)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
A	2004-2009	10,000	10,000	-	-	-	-	-	-	-	-	-	-	-
B	2014	3,000	3,000	3,000	3,000	3,000	3,000	3,000	-	-	-	-	-	-
C	2018	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	-	-
D	2018	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	-	-
Total		76,000	76,000	66,000	66,000	66,000	66,000	66,000	63,000	63,000	63,000	63,000	50,000	50,000

Table 3
LSE's Vintaged Annual Load Share Percentages

		Annual Vintaged Load Shares (%)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	66%	66%	76%	76%	76%	76%	76%	79%	79%	79%	79%	100%	100%
A	2004-2009	13%	13%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
B	2014	4%	4%	5%	5%	5%	5%	5%	0%	0%	0%	0%	0%	0%
C	2018	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	0%	0%
D	2018	16%	16%	18%	18%	18%	18%	18%	19%	19%	19%	19%	0%	0%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 4

LSE's Vintaged Coincident Peak Load Shares

		Annual Vintaged Peak Loads (MW)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000
A	2004-2009	2,500	2,500	-	-	-	-	-	-	-	-	-	-	-
B	2014	800	800	800	800	800	800	800	-	-	-	-	-	-
C	2018	300	300	300	300	300	300	300	300	300	300	300	-	-
D	2018	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	-	-
Total		20,100	20,100	17,600	17,600	17,600	17,600	17,600	16,800	16,800	16,800	16,800	13,000	13,000

Table 5

LSE's Vintaged Coincident Peak Load Share Percentages

		Annual Vintaged Peak Load Shares (%)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	65%	65%	74%	74%	74%	74%	74%	77%	77%	77%	77%	100%	100%
A	2004-2009	12%	12%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
B	2014	4%	4%	5%	5%	5%	5%	5%	0%	0%	0%	0%	0%	0%
C	2018	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	0%	0%
D	2018	17%	17%	20%	20%	20%	20%	20%	21%	21%	21%	21%	0%	0%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 6
Model IOU Portfolio

Contract #	Vintage	Contract Type	Local RA	System RA	Flex RA	RPS Energy	GHG-Free Energy	PPA Price ($/MWh)	RA Price ($/kW-mo)	Online Date	Term (Years)	Termination Date	Technology	Installed AC Capacity (MW)	Expected Annual Energy Production (GWh)
1	CTC-Eligible	Bundled	Yes	Yes	Yes	No	Large Hydro	$20		1/1/1910	130	1/1/2040	Large Hydro	200	736
2	CTC-Eligible	Bundled	No	Yes	Yes	No	Large Hydro	$25		1/1/1935	100	1/1/2035	Large Hydro	50	184
3	CTC-Eligible	Bundled	Yes	Yes	Yes	No	Nuclear	$32		1/1/1965	70	1/1/2035	Nuclear	1000	8059
4	CTC-Eligible	Bundled	Yes	Yes	Yes	No	No	$35		1/1/1990	40	1/1/2030	Gas CCGT	800	3854
5	2004-2009	Bundled	Yes	Yes	Yes	No	No	$45		1/1/2010	40	1/1/2050	Gas Peaker	50	53
6	2004-2009	Bundled	No	Yes	No	Yes	No	$250		1/1/2011	20	1/1/2031	Wind	90	205
7	2004-2009	Bundled	No	Yes	No	Yes	No	$120		7/1/2011	20	7/1/2031	Geothermal	100	666
8	2010	Bundled	No	Yes	No	Yes	No	$200		1/1/2012	20	1/1/2032	Wind	50	114
9	2011	Bundled	No	Yes	No	Yes	No	$250		1/1/2014	20	1/1/2034	Solar	300	736
10	2014	Bundled	No	Yes	No	Yes	No	$180		1/1/2018	20	1/1/2038	Solar	150	368
11	2015	Bundled	No	Yes	No	Yes	No	$140		1/1/2018	15	1/1/2033	Wind	100	228
12	2016	Bundled	No	Yes	No	Yes	No	$50		1/1/2020	15	1/1/2035	Solar	150	368
13	2017	Bundled	No	Yes	No	Yes	No	$45		1/1/2020	20	1/1/2040	Solar	100	245
14	2017	Bundled	No	Yes	No	Yes	No	$42		1/1/2019	10	1/1/2029	Wind	60	137
15	2017	RA-only	Yes	Yes	No	No	No		$4.50	1/1/2022	2	1/1/2024	Gas Peaker	50	0
16	2018	RA-only	Yes	Yes	Yes	No	No		$5.00	7/1/2022	2	7/1/2024	Gas CCGT	800	0
17	2020	RA-only	Yes	Yes	No	No	No		$3.40	1/1/2023	1	1/1/2024	Gas CCGT	500	0
18	2020	RA-only	No	Yes	Yes	No	No		$5.50	7/1/2023	0.25	10/1/2023	Gas CCGT	300	0
19	2020	RA-only	No	Yes	No	No	No		$3.00	3/1/2023	0.5	8/31/2023	Gas Peaker	100	0

Table 7

GHG-Free, Large Hydro Position by Contract

Contract	Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	CTC-Eligible	736	736	736	736	736	736	736	736	736	736	736	736	736	736
2	CTC-Eligible	184	184	184	184	184	184	184	184	184	184	184	184	-	-
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		920	920	920	920	920	920	920	920	920	920	920	920	736	736

Table 8

GHG-Free, Large Hydro Position by Vintage

Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
CTC-Eligible	920	920	920	920	920	920	920	920	920	920	920	920	736	736
2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	920	920	920	920	920	920	920	920	920	920	920	920	736	736

Table 9

GHG-Free, Large Hydro Allocation Eligibility (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	605	605	605	605	605	605	605	605	605	605	605	605	484	484
A	121	121	121	121	121	121	121	121	121	121	121	121	97	97
B	36	36	36	36	36	36	36	36	36	36	36	36	29	29
C	12	12	12	12	12	12	12	12	12	12	12	12	10	10
D	145	145	145	145	145	145	145	145	145	145	145	145	116	116
Total	920	920	920	920	920	920	920	920	920	920	920	920	736	736

Table 10

Large Hydro Allocations Accepted

LSE	Allocation Election	2023 Large Hydro Allocation (GWh)
IOU	100%	605
A	100%	121
B	0%	-
C	100%	12
D	100%	145
Total		883
Unallocated		36

Table 11

Large Hydro Re-Allocations

LSE	Re-Allocation Percentage	2023 Large Hydro Re-Allocation (GWh)
IOU	68%	25
A	14%	5
B	0%	-
C	1%	0
D	16%	6
Total		36

Table 12

Total Large Hydro Allocations

LSE	2023 Large Hydro Allocation (GWh)
IOU	630
A	126
B	-
C	13
D	151
Total	920

Table 13

GHG-Free, Nuclear Position by Contract (GWh)

Contract	Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-

Table 14

GHG-Free, Nuclear Position by Vintage (GWh)

Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
CTC-Eligible	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-
2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-

Table 15
GHG-Free, Nuclear Allocation Eligibility (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	5,302	-	-
A	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	-	-
B	318	318	318	318	318	318	318	318	318	318	318	318	-	-
C	106	106	106	106	106	106	106	106	106	106	106	106	-	-
D	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	-	-
Total	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	8,059	-	-

Table 16
Nuclear Allocations Accepted

LSE	Allocation Election	2023 Nuclear Energy Allocation (GWh)
IOU	100%	5,302
A	100%	1,060
B	0%	-
C	0%	-
D	0%	-
Total		6,363
Unallocated		1,697

Table 17
Nuclear Re-Allocations

LSE	Re-Allocation Percentage	2023 Nuclear Energy Re-Allocation (GWh)
IOU	83%	1,414
A	17%	283
B	0%	-
C	0%	-
D	0%	-
Total		1,697

Table 18
Total Nuclear Allocation

LSE	2023 Nuclear Energy Allocation (GWh)
IOU	6,716
A	1,343
B	-
C	-
D	-
Total	8,059

Table 19

RPS Energy Position by Contract (GWh)

Contract	Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	205	205	205	205	205	205	205	205	-	-	-	-	-	-
7	2004-2009	666	666	666	666	666	666	666	666	-	-	-	-	-	-
8	2010	114	114	114	114	114	114	114	114	114	-	-	-	-	-
9	2011	736	736	736	736	736	736	736	736	736	736	736	-	-	-
10	2014	368	368	368	368	368	368	368	368	368	368	368	368	368	368
11	2015	228	228	228	228	228	228	228	228	228	228	-	-	-	-
12	2016	368	368	368	368	368	368	368	368	368	368	368	368	-	-
13	2017	245	245	245	245	245	245	245	245	245	245	245	245	245	245
14	2017	137	137	137	137	137	137	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,059	1,945	1,717	981	613	613

Table 20
RPS Energy Position by Vintage (GWh)

Vintage	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2004-2009	871	871	871	871	871	871	871	871	-	-	-	-	-	-
2010	114	114	114	114	114	114	114	114	114	-	-	-	-	-
2011	736	736	736	736	736	736	736	736	736	736	736	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2014	368	368	368	368	368	368	368	368	368	368	368	368	368	368
2015	228	228	228	228	228	228	228	228	228	228	-	-	-	-
2016	368	368	368	368	368	368	368	368	368	368	368	368	-	-
2017	382	382	382	382	382	382	245	245	245	245	245	245	245	245
2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,059	1,945	1,717	981	613	613

Table 21

RPS Energy Allocation Eligibility (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	2,271	2,271	2,271	2,271	2,271	2,271	2,163	2,163	1,590	1,504	1,323	765	473	473
A	115	115	115	115	115	115	115	115	-	-	-	-	-	-
B	90	90	90	90	90	90	90	90	55	50	50	17	17	17
C	45	45	45	45	45	45	43	43	32	30	26	15	9	9
D	545	545	545	545	545	545	519	519	382	361	317	184	114	114
Total	3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,059	1,945	1,717	981	613	613

Table 22

RPS Energy Long-Term Allocations Accepted (GWh)

LSE	Allocation Election (Long-Term)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	100%	2,271	2,271	2,271	2,271	2,271	2,271	2,163	2,163	1,590	1,504	1,323	765	473	473
A	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C	70%	32	32	32	32	32	32	30	30	22	21	19	11	7	7
D	50%	273	273	273	273	273	273	260	260	191	180	159	92	57	57
Total		2,576	2,576	2,576	2,576	2,576	2,576	2,453	2,453	1,803	1,705	1,500	868	537	537

Table 23

RPS Energy Short-Term Allocations Accepted (GWh)

LSE	Allocation Election (Short-Term)	2023
IOU	0%	-
A	0%	-
B	0%	-
C	30%	14
D	0%	-
Total		14

Table 24

Total RPS Energy Allocations Accepted (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	2,271	2,271	2,271	2,271	2,271	2,271	2,163	2,163	1,590	1,504	1,323	765	473	473
A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C	45	32	32	32	32	32	30	30	22	21	19	11	7	7
D	273	273	273	273	273	273	260	260	191	180	159	92	57	57
Total	2,589	2,576	2,576	2,576	2,576	2,576	2,453	2,453	1,803	1,705	1,500	868	537	537

Table 25

2023 RPS Allocation Payments

LSE	2023 RPS Allocation Payment ($)
IOU	$ 40,881,567
A	$ -
B	$ -
C	$ 817,631
D	$ 4,905,788
Total	$ 46,604,986

Table 26

Distribution of 2023 RPS Allocation Payments Across Vintages ($)

Vintage	2023 RPS Allocation Payment ($)
CTC-Eligible	$ -
2004-2009	$ 11,755,044.00
2010	$ 1,770,316.36
2011	$ 11,438,967.27
2012	$ -
2013	$ -
2014	$ 5,719,483.64
2015	$ 3,709,234.29
2016	$ 5,991,840.00
2017	$ 6,220,100.57
2018	$ -
2019	$ -
2020	$ -
Total	$ 46,604,986

Table 27

RPS Allocations Declined (GWh)

LSE	2023
IOU	-
A	115
B	90
C	-
D	273
Total	477

Table 28

RPS Energy Available for Long-Term Market Offer (GWh)

Long-Term RPS Sales Cap	35%

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
A	40	40	40	40	40	40	40	40	-	-	-	-	-	-
B	31	31	31	31	31	31	31	31	19	18	18	6	6	6
C	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D	95	95	95	95	95	95	95	95	95	95	95	64	40	40
Max Long-Term for Market Offer	167	167	167	167	167	167	167	167	115	113	113	70	46	46
Total for Market Offer	477													

Table 29
2023 RPS Market Offer Bids and Selections

Bid #	% of Generation	Price ($/MWh)	Term (Years)	Volume (GWh)	Long-Term Volume (GWh)	Cumulative Long-Term Volume (GWh)	Total Cumulative Volume (GWh)	Bid Selection	Volume Sold (GWh)	% Sold	Term	2023 Revenues ($)
1	20%	$22	1	95	0	0	95	Selected	95	20%	Short-Term	$2,098,070
2	30%	$17	1	143	0	0	238	Selected	143	30%	Short-Term	$2,431,854
3	20%	$16	10	33	33	33	272	Selected	33	20%	Long-Term	$534,054
4	10%	$15	1	48	0	33	319	Selected	48	10%	Short-Term	$715,251
5	25%	$14	1	119	0	33	439	Selected	119	25%	Short-Term	$1,668,919
6	5%	$12	12	8	8	42	447	Partially Selected	8	5%	Long-Term	$100,135
7	40%	$9	1	191	0	42	477	Partially Selected	30	6%	Short-Term	$268,219
8	20%	$8	10	33	33	75	477	Not Selected	0	0%	Long-Term	$0
9	100%	$2	14	167	167	167	477	Not Selected	0	0%	Long-Term	$0
10	100%	$1	1	477	0	167	477	Not Selected	0	0%	Short-Term	$0
Total								Total GWh	477		Total Revenues	$7,816,503
								Short-Term	435	91%	Weighted Avg Price	$16.39
								Long-Term	42	25%		

Table 30

2023 RPS Market Offer Revenue Allocation by Vintage

Vintage	2023 Declined RPS Volumes (GWh)	2023 Revenues ($)
CTC-Eligible	0	$0
2004-2009	218	$3,568,418
2010	16	$254,561
2011	100	$1,644,853
2012	0	$0
2013	0	$0
2014	50	$822,427
2015	22	$355,577
2016	35	$574,393
2017	36	$596,275
2018	0	$0
2019	0	$0
2020	0	$0
Total	477	$7,816,503

Table 31

2023 RPS Market Offer Revenue Allocation by LSE

LSE	2023 Declined RPS Volumes (GWh)	2023 Revenues ($)
IOU	0	$ -
A	115	$ 1,878,115
B	90	$ 1,470,715
C	0	$ -
D	273	$ 4,467,674
Total	477	$ 7,816,503

Table 32

Source of Long-Term RPS Sales (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
A	10	10	10	10	10	10	10	10	-	-	-	-	-	-
B	8	8	8	8	8	8	8	8	5	4	4	1	1	1
C	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D	24	24	24	24	24	24	24	24	24	24	24	16	10	10
Total	42	42	42	42	42	42	42	42	29	28	28	18	11	11

Table 33

RPS Energy Available for IRP CNS Credit (GWh)

LSE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IOU	2,271	2,271	2,271	2,271	2,271	2,271	2,163	2,163	1,590	1,504	1,323	765	473	473
A	-	105	105	105	105	105	105	105	-	-	-	-	-	-
B	-	82	82	82	82	82	82	82	51	46	46	15	15	15
C	45	45	45	45	45	45	43	43	32	30	26	15	9	9
D	273	521	521	521	521	521	495	495	358	337	294	168	104	104
Total	2,589	3,024	3,024	3,024	3,024	3,024	2,888	2,888	2,030	1,916	1,689	964	602	602

Table 34

Monthly Effective Load Carrying Capacity (ELCC)

	Month											
Technology	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Solar	4%	3%	18%	15%	16%	31%	39%	27%	14%	2%	2%	0%
Wind	14%	12%	28%	25%	25%	33%	23%	21%	15%	8%	12%	13%
Geothermal	95%	92%	88%	76%	74%	70%	84%	82%	83%	86%	93%	95%
Biomass	82%	86%	84%	76%	83%	89%	87%	90%	90%	81%	85%	86%
Small Hydro	60%	70%	73%	72%	69%	74%	73%	72%	71%	64%	56%	64%
Large Hydro	60%	70%	73%	72%	69%	74%	73%	72%	71%	64%	56%	64%
Nuclear	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Gas CCGT	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Gas Peaker	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 35

Monthly Contract NQC Value (MW)

		Month											
Contract #	**Technology**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	Large Hydro	120	140	146	144	138	148	146	144	142	128	112	128
2	Large Hydro	30	35	37	36	35	37	37	36	36	32	28	32
3	Nuclear	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	Gas CCGT	800	800	800	800	800	800	800	800	800	800	800	800
5	Gas Peaker	50	50	50	50	50	50	50	50	50	50	50	50
6	Wind	13	11	25	23	23	30	21	19	14	7	11	12
7	Geothermal	95	92	88	76	74	70	84	82	83	86	93	95
8	Wind	7	6	14	13	13	17	12	11	8	4	6	7
9	Solar	12	9	54	45	48	93	117	81	42	6	6	-
10	Solar	6	5	27	23	24	47	59	41	21	3	3	-
11	Wind	14	12	28	25	25	33	23	21	15	8	12	13
12	Solar	6	5	27	23	24	47	59	41	21	3	3	-
13	Solar	4	3	18	15	16	31	39	27	14	2	2	-
14	Wind	8	7	17	15	15	20	14	13	9	5	7	8
15	Gas Peaker	50	50	50	50	50	50	50	50	50	50	50	50
16	Gas CCGT	800	800	800	800	800	800	800	800	800	800	800	800
17	Gas CCGT	500	500	500	500	500	500	500	500	500	500	500	500
18	Gas CCGT	300	300	300	300	300	300	300	300	300	300	300	300
19	Gas Peaker	100	100	100	100	100	100	100	100	100	100	100	100
	Total	3,915	3,924	4,081	4,036	4,034	4,171	4,209	4,114	4,004	3,884	3,883	3,894

Table 36
Local RA Position by Contract (MW)

		Month											
Contract	**Vintage**	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
1	CTC-Eligible	120	140	146	144	138	148	146	144	142	128	112	128
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	CTC-Eligible	800	800	800	800	800	800	800	800	800	800	800	800
5	2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	50	50	50	50	50	50	50	50	50	50	50	50
16	2018	800	800	800	800	800	800	800	800	800	800	800	800
17	2020	500	500	500	500	500	500	500	500	500	500	500	500
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		3,320	3,340	3,346	3,344	3,338	3,348	3,346	3,344	3,342	3,328	3,312	3,328

		Month (continued)											
Contract	**Vintage**	**1/1/2024**	**2/1/2024**	**3/1/2024**	**4/1/2024**	**5/1/2024**	**6/1/2024**	**7/1/2024**	**8/1/2024**	**9/1/2024**	**10/1/2024**	**11/1/2024**	**12/1/2024**
1	CTC-Eligible	120	140	146	144	138	148	146	144	142	128	112	128
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	CTC-Eligible	800	800	800	800	800	800	800	800	800	800	800	800
5	2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	800	800	800	800	800	800	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		2,770	2,790	2,796	2,794	2,788	2,798	1,996	1,994	1,992	1,978	1,962	1,978

		Month (continued)											
Contract	**Vintage**	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**
1	CTC-Eligible	120	140	146	144	138	148	146	144	142	128	112	128
2	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
3	CTC-Eligible	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	CTC-Eligible	800	800	800	800	800	800	800	800	800	800	800	800
5	2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
6	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
7	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
8	2010	-	-	-	-	-	-	-	-	-	-	-	-
9	2011	-	-	-	-	-	-	-	-	-	-	-	-
10	2014	-	-	-	-	-	-	-	-	-	-	-	-
11	2015	-	-	-	-	-	-	-	-	-	-	-	-
12	2016	-	-	-	-	-	-	-	-	-	-	-	-
13	2017	-	-	-	-	-	-	-	-	-	-	-	-
14	2017	-	-	-	-	-	-	-	-	-	-	-	-
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		1,970	1,990	1,996	1,994	1,988	1,998	1,996	1,994	1,992	1,978	1,962	1,978

Table 37

Local RA Position by Vintage (MW)

Vintage	Month											
	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023
CTC-Eligible	1,920	1,940	1,946	1,944	1,938	1,948	1,946	1,944	1,942	1,928	1,912	1,928
2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
2010	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-
2017	50	50	50	50	50	50	50	50	50	50	50	50
2018	800	800	800	800	800	800	800	800	800	800	800	800
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	500	500	500	500	500	500	500	500	500	500	500	500
Total	3,320	3,340	3,346	3,344	3,338	3,348	3,346	3,344	3,342	3,328	3,312	3,328

Vintage	Month (continued)											
	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024
CTC-Eligible	1,920	1,940	1,946	1,944	1,938	1,948	1,946	1,944	1,942	1,928	1,912	1,928
2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
2010	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-
2018	800	800	800	800	800	800	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	2,770	2,790	2,796	2,794	2,788	2,798	1,996	1,994	1,992	1,978	1,962	1,978

Vintage	Month (continued)											
	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025
CTC-Eligible	1,920	1,940	1,946	1,944	1,938	1,948	1,946	1,944	1,942	1,928	1,912	1,928
2004-2009	50	50	50	50	50	50	50	50	50	50	50	50
2010	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,970	1,990	1,996	1,994	1,988	1,998	1,996	1,994	1,992	1,978	1,962	1,978

Table 38
Local RA Allocations (MW)

LSE	Month											
	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023
IOU	2,432	2,445	2,449	2,447	2,444	2,450	2,449	2,447	2,446	2,437	2,427	2,437
A	245	248	248	248	247	249	248	248	248	246	244	246
B	78	79	79	79	79	80	79	79	79	79	78	79
C	45	45	45	45	45	45	45	45	45	45	44	45
D	520	524	525	524	523	525	525	524	524	522	519	522
Total	3,320	3,340	3,346	3,344	3,338	3,348	3,346	3,344	3,342	3,328	3,312	3,328

LSE	Month (continued)											
	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024
IOU	1,893	1,906	1,910	1,909	1,905	1,911	1,291	1,290	1,288	1,279	1,269	1,279
A	245	248	248	248	247	249	248	248	248	246	244	246
B	78	79	79	79	79	80	79	79	79	79	78	79
C	44	44	44	44	44	44	30	30	30	30	29	30
D	510	513	514	514	513	515	348	347	347	344	342	344
Total	2,770	2,790	2,796	2,794	2,788	2,798	1,996	1,994	1,992	1,978	1,962	1,978

LSE	Month (continued)											
	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025
IOU	1,274	1,287	1,291	1,290	1,286	1,292	1,291	1,290	1,288	1,279	1,269	1,279
A	245	248	248	248	247	249	248	248	248	246	244	246
B	78	79	79	79	79	80	79	79	79	79	78	79
C	29	30	30	30	30	30	30	30	30	30	29	30
D	343	347	348	347	346	348	348	347	347	344	342	344
Total	1,970	1,990	1,996	1,994	1,988	1,998	1,996	1,994	1,992	1,978	1,962	1,978

Table 39
System RA Position by Contract (MW)

Contract	Vintage	Month 1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	13	11	25	23	23	30	21	19	14	7	11	12
7	2004-2009	95	92	88	76	74	70	84	82	83	86	93	95
8	2010	7	6	14	13	13	17	12	11	8	4	6	7
9	2011	12	9	54	45	48	93	117	81	42	6	6	-
10	2014	6	5	27	23	24	47	59	41	21	3	3	-
11	2015	14	12	28	25	25	33	23	21	15	8	12	13
12	2016	6	5	27	23	24	47	59	41	21	3	3	-
13	2017	4	3	18	15	16	31	39	27	14	2	2	-
14	2017	8	7	17	15	15	20	14	13	9	5	7	8
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	300	300	300	300	-	-
19	2020	-	-	100	100	100	100	100	100	-	-	-	-
Total		195	184	435	392	396	523	863	770	562	456	171	166

Contract	Vintage	Month (continued) 1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	13	11	25	23	23	30	21	19	14	7	11	12
7	2004-2009	95	92	88	76	74	70	84	82	83	86	93	95
8	2010	7	6	14	13	13	17	12	11	8	4	6	7
9	2011	12	9	54	45	48	93	117	81	42	6	6	-
10	2014	6	5	27	23	24	47	59	41	21	3	3	-
11	2015	14	12	28	25	25	33	23	21	15	8	12	13
12	2016	6	5	27	23	24	47	59	41	21	3	3	-
13	2017	4	3	18	15	16	31	39	27	14	2	2	-
14	2017	8	7	17	15	15	20	14	13	9	5	7	8
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		195	184	335	292	296	423	463	370	262	156	171	166

Contract	Vintage	Month (continued) 1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025
1	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
2	CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
3	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
4	CTC-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
5	2004-2009	-	-	-	-	-	-	-	-	-	-	-	-
6	2004-2009	13	11	25	23	23	30	21	19	14	7	11	12
7	2004-2009	95	92	88	76	74	70	84	82	83	86	93	95
8	2010	7	6	14	13	13	17	12	11	8	4	6	7
9	2011	12	9	54	45	48	93	117	81	42	6	6	-
10	2014	6	5	27	23	24	47	59	41	21	3	3	-
11	2015	14	12	28	25	25	33	23	21	15	8	12	13
12	2016	6	5	27	23	24	47	59	41	21	3	3	-
13	2017	4	3	18	15	16	31	39	27	14	2	2	-
14	2017	8	7	17	15	15	20	14	13	9	5	7	8
15	2017	-	-	-	-	-	-	-	-	-	-	-	-
16	2018	-	-	-	-	-	-	-	-	-	-	-	-
17	2020	-	-	-	-	-	-	-	-	-	-	-	-
18	2020	-	-	-	-	-	-	-	-	-	-	-	-
19	2020	-	-	-	-	-	-	-	-	-	-	-	-
Total		195	184	335	292	296	423	463	370	262	156	171	166

Table 40

System RA Position by Vintage (MW)

	Month											
Vintage	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023
CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
2004-2009	108	103	113	99	97	100	105	101	97	93	104	107
2010	7	6	14	13	13	17	12	11	8	4	6	7
2011	12	9	54	45	48	93	117	81	42	6	6	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	6	5	27	23	24	47	59	41	21	3	3	-
2015	14	12	28	25	25	33	23	21	15	8	12	13
2016	6	5	27	23	24	47	59	41	21	3	3	-
2017	12	10	35	30	31	51	53	40	23	7	9	8
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	100	100	100	100	400	400	300	300	-	-
Total	195	184	435	392	396	523	863	770	562	456	171	166

	Month (continued)											
Vintage	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024
CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
2004-2009	108	103	113	99	97	100	105	101	97	93	104	107
2010	7	6	14	13	13	17	12	11	8	4	6	7
2011	12	9	54	45	48	93	117	81	42	6	6	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	6	5	27	23	24	47	59	41	21	3	3	-
2015	14	12	28	25	25	33	23	21	15	8	12	13
2016	6	5	27	23	24	47	59	41	21	3	3	-
2017	12	10	35	30	31	51	53	40	23	7	9	8
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	195	184	335	292	296	423	463	370	262	156	171	166

	Month (continued)											
Vintage	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025
CTC-Eligible	30	35	37	36	35	37	37	36	36	32	28	32
2004-2009	108	103	113	99	97	100	105	101	97	93	104	107
2010	7	6	14	13	13	17	12	11	8	4	6	7
2011	12	9	54	45	48	93	117	81	42	6	6	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	6	5	27	23	24	47	59	41	21	3	3	-
2015	14	12	28	25	25	33	23	21	15	8	12	13
2016	6	5	27	23	24	47	59	41	21	3	3	-
2017	12	10	35	30	31	51	53	40	23	7	9	8
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	195	184	335	292	296	423	463	370	262	156	171	166

Table 41

System RA Allocation Eligibility (MW)

	Month											
LSE	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
IOU	133	124	336	306	309	404	733	664	483	404	115	111
A	17	17	19	17	16	17	18	17	16	16	16	17
B	7	6	10	9	9	13	14	11	8	6	6	6
C	3	3	5	5	5	7	8	6	4	2	3	3
D	36	33	64	55	56	82	90	71	49	28	31	30
Total	195	184	435	392	396	523	863	770	562	456	171	166

	Month (continued)											
LSE	**1/1/2024**	**2/1/2024**	**3/1/2024**	**4/1/2024**	**5/1/2024**	**6/1/2024**	**7/1/2024**	**8/1/2024**	**9/1/2024**	**10/1/2024**	**11/1/2024**	**12/1/2024**
IOU	133	124	236	206	209	304	333	264	183	104	115	111
A	17	17	19	17	16	17	18	17	16	16	16	17
B	7	6	10	9	9	13	14	11	8	6	6	6
C	3	3	5	5	5	7	8	6	4	2	3	3
D	36	33	64	55	56	82	90	71	49	28	31	30
Total	195	184	335	292	296	423	463	370	262	156	171	166

	Month (continued)											
LSE	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**
IOU	133	124	236	206	209	304	333	264	183	104	115	111
A	17	17	19	17	16	17	18	17	16	16	16	17
B	7	6	10	9	9	13	14	11	8	6	6	6
C	3	3	5	5	5	7	8	6	4	2	3	3
D	36	33	64	55	56	82	90	71	49	28	31	30
Total	195	184	335	292	296	423	463	370	262	156	171	166

Table 42

2023 System RA Allocations Accepted (MW)

LSE	Allocation Election %	Month 1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023
IOU	100%	133	124	336	306	309	404	733	664	483	404	115	111
A	0%	-	-	-	-	-	-	-	-	-	-	-	-
B	50%	3	3	5	4	5	6	7	6	4	3	3	3
C	0%	-	-	-	-	-	-	-	-	-	-	-	-
D	80%	29	27	51	44	45	66	72	57	39	22	25	24
Available for Market Offer (MW)		31	30	42	37	37	47	50	43	35	26	28	29
Total (MW)		195	184	435	392	396	523	863	770	562	456	171	166

Table 43
2023 System RA Allocation Payments by LSE ($)

LSE	Month 1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	Total
IOU	$596,396	$558,848	$1,514,158	$1,377,230	$1,390,707	$1,820,104	$3,300,170	$2,989,235	$2,173,958	$1,819,580	$ 517,723	$ 497,713	$18,555,821
A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
B	$ 14,879	$ 14,335	$ 23,122	$ 20,227	$ 20,373	$ 28,196	$ 31,770	$ 25,760	$ 19,031	$ 12,541	$ 13,337	$ 13,086	$ 236,657
C	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
D	$128,454	$120,367	$ 229,203	$ 199,711	$ 202,614	$ 295,099	$ 323,113	$ 256,143	$ 177,468	$ 101,140	$ 111,510	$ 107,200	$ 2,252,023
Total	$739,729	$693,550	$1,766,483	$1,597,168	$1,613,694	$2,143,400	$3,655,053	$3,271,138	$2,370,457	$1,933,262	$ 642,569	$ 617,998	$21,044,501

Table 44
Distribution of 2023 System RA Allocation Payments Across Vintages ($)

Vintage	Month 1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	Total
CTC-Eligible	$108,806	$126,940	$ 132,381	$ 130,567	$ 125,127	$ 134,194	$ 132,381	$ 130,567	$ 128,754	$ 116,060	$ 101,552	$ 116,060	$ 1,483,388
2004-2009	$390,251	$372,842	$ 410,561	$ 357,246	$ 349,993	$ 361,599	$ 379,733	$ 365,951	$ 349,993	$ 338,024	$ 376,469	$ 386,987	$ 4,439,646
2010	$ 28,994	$ 24,852	$ 57,989	$ 51,776	$ 51,776	$ 68,344	$ 47,634	$ 43,491	$ 31,065	$ 16,568	$ 24,852	$ 26,923	$ 474,264
2011	$ 49,705	$ 37,278	$ 223,670	$ 186,392	$ 198,818	$ 385,210	$ 484,619	$ 335,506	$ 173,966	$ 24,852	$ 24,852	$ -	$ 2,124,869
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ 24,852	$ 18,639	$ 111,835	$ 93,196	$ 99,409	$ 192,605	$ 242,310	$ 167,753	$ 86,983	$ 12,426	$ 12,426	$ -	$ 1,062,435
2015	$ 59,250	$ 50,786	$ 118,500	$ 105,804	$ 105,804	$ 139,661	$ 97,339	$ 88,875	$ 63,482	$ 33,857	$ 50,786	$ 55,018	$ 969,161
2016	$ 25,393	$ 19,045	$ 114,268	$ 95,223	$ 101,571	$ 196,795	$ 247,580	$ 171,402	$ 88,875	$ 12,696	$ 12,696	$ -	$ 1,085,545
2017	$ 52,479	$ 43,168	$ 147,279	$ 126,964	$ 131,196	$ 214,993	$ 223,457	$ 167,593	$ 97,339	$ 28,779	$ 38,936	$ 33,011	$ 1,305,193
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$1,800,000	$1,800,000	$1,350,000	$1,350,000	$ -	$ -	$ 8,100,000
Total	$739,729	$693,550	$1,766,483	$1,597,168	$1,613,694	$2,143,400	$3,655,053	$3,271,138	$2,370,457	$1,933,262	$ 642,569	$ 617,998	$21,044,501

Table 45

2023 Declined System RA (MW)

		Month												
LSE	**Allocation Election %**	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Total**
IOU	100%	-	-	-	-	-	-	-	-	-	-	-	-	-
A	0%	17	17	19	17	16	17	18	17	16	16	16	17	203
B	50%	3	3	5	4	5	6	7	6	4	3	3	3	53
C	0%	3	3	5	5	5	7	8	6	4	2	3	3	54
D	80%	7	7	13	11	11	16	18	14	10	6	6	6	125
Total		31	30	42	37	37	47	50	43	35	26	28	29	434

Table 46

2023 System RA Market Offer Bids

Bid #	Volume (MW)	Price ($/kW-mo)	Offer Term 1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	Revenue ($)	Selected
1	5	$6.00	0	0	0	0	0	0	0	0	1	0	0	0	$0	0
2	10	$5.50	0	0	0	0	0	1	1	1	0	0	0	0	$165,000	1
3	49	$1.50	1	1	1	1	1	1	1	1	1	1	1	1	$0	0
4	20	$2.50	1	1	1	1	1	1	1	1	1	1	1	1	$0	0
5	25	$4.25	0	0	0	1	1	1	1	1	1	0	0	0	$0	0
6	10	$5.25	0	0	0	0	0	0	1	1	1	0	0	0	$157,500	1
7	2	$5.75	0	0	0	1	1	1	1	1	1	0	0	0	$69,000	1
8	5	$3.50	0	0	0	1	1	1	1	1	1	1	1	1	$157,500	1
9	30	$4.00	0	0	0	0	0	0	1	1	0	0	0	0	$0	0
10	15	$2.75	1	1	1	1	1	1	1	1	1	1	1	1	$495,000	1
														Total Revenues ($)	$1,044,000	
														Weighted Average Sales Price ($/kW-mo)	$3.52	
														Weighted Average Price (Sold & Unsold) ($/kW-mo)	$2.40	

Table 47

2023 System RA Volumes Sold in Market Offer (MW)

Offer #	Monthly Volumes Selected 1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	Total
1	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	10	10	10	0	0	0	0	30
3	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	10	10	10	0	0	0	30
7	0	0	0	2	2	2	2	2	2	0	0	0	12
8	0	0	0	5	5	5	5	5	5	5	5	5	45
9	0	0	0	0	0	0	0	0	0	0	0	0	0
10	15	15	15	15	15	15	15	15	15	15	15	15	180
Total	15	15	15	22	22	32	42	42	32	20	20	20	297

Table 48

2023 Unsold System RA (MW)

	Month												
	1/1/2023	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Total**
Unsold System RA (MW)	16	15	27	15	15	15	8	1	3	6	8	9	137
												Total RA (Sold and Unsold)	434

Table 49

2023 Unsold System RA by Vintage (MW)

	Month											
Vintage	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
CTC-Eligible	3.0	3.4	4.5	2.8	2.7	2.3	1.2	0.2	0.5	1.5	1.6	1.9
2004-2009	10.6	9.9	14.1	7.8	7.6	6.1	3.3	0.5	1.5	4.4	5.9	6.3
2010	0.3	0.2	0.7	0.4	0.4	0.4	0.2	0.0	0.0	0.1	0.1	0.2
2011	0.5	0.4	2.8	1.5	1.5	2.3	1.5	0.2	0.3	0.1	0.1	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	0.2	0.2	1.4	0.7	0.8	1.2	0.8	0.1	0.1	0.1	0.1	-
2015	0.4	0.4	1.1	0.6	0.6	0.6	0.2	0.0	0.1	0.1	0.2	0.2
2016	0.2	0.1	1.0	0.5	0.6	0.9	0.6	0.1	0.1	0.0	0.1	-
2017	0.4	0.3	1.3	0.7	0.7	1.0	0.5	0.1	0.1	0.1	0.2	0.1
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
Total	16	15	27	15	15	15	8	1	3	6	8	9

Table 50

2023 Unsold System RA Re-Allocations (MW)

	Month											
LSE	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
IOU	10.3	9.8	18.3	10.2	10.1	10.2	5.7	0.7	1.8	4.2	5.4	5.7
A	1.7	1.7	2.3	1.3	1.3	1.0	0.6	0.1	0.3	0.7	0.9	1.0
B	0.6	0.6	1.0	0.5	0.5	0.5	0.3	0.0	0.1	0.2	0.3	0.3
C	0.2	0.2	0.4	0.2	0.2	0.2	0.1	0.0	0.0	0.1	0.1	0.1
D	2.8	2.6	4.9	2.8	2.7	2.7	1.5	0.2	0.5	1.1	1.5	1.5
Total	16	15	27	15	15	15	8	1	3	6	8	9

Table 51

2023 Total System RA Allocations (MW)

	Month											
LSE	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**
IOU	143	134	355	316	319	415	739	665	485	409	120	116
A	2	2	2	1	1	1	1	0	0	1	1	1
B	4	4	6	5	5	7	7	6	4	3	3	3
C	0	0	0	0	0	0	0	0	0	0	0	0
D	31	29	56	47	48	68	73	57	40	24	26	25
Total Allocated	180	169	420	370	374	491	821	728	530	436	151	146
Total Sold	15	15	15	22	22	32	42	42	32	20	20	20
Total RA	195	184	435	392	396	523	863	770	562	456	171	166

Table 52

2023 Market Offer Revenue Allocation across Vintages ($)

	Month												
Vintage	**1/1/2023**	**2/1/2023**	**3/1/2023**	**4/1/2023**	**5/1/2023**	**6/1/2023**	**7/1/2023**	**8/1/2023**	**9/1/2023**	**10/1/2023**	**11/1/2023**	**12/1/2023**	**Total**
CTC-Eligible	$ 13,988	$ 16,319	$ 17,019	$ 16,786	$ 16,086	$ 17,252	$ 17,019	$ 16,786	$ 16,552	$ 14,921	$ 13,055	$ 14,921	$ 190,703
2004-2009	$ 50,170	$ 47,932	$ 52,781	$ 45,927	$ 44,995	$ 46,487	$ 48,818	$ 47,046	$ 44,995	$ 43,456	$ 48,399	$ 49,751	$ 570,758
2010	$ 1,338	$ 1,147	$ 2,676	$ 2,389	$ 2,389	$ 3,154	$ 2,198	$ 2,007	$ 1,434	$ 765	$ 1,147	$ 1,242	$ 21,887
2011	$ 2,294	$ 1,720	$ 10,322	$ 8,602	$ 9,175	$ 17,777	$ 22,365	$ 15,483	$ 8,028	$ 1,147	$ 1,147	$ -	$ 98,062
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ 1,147	$ 860	$ 5,161	$ 4,301	$ 4,588	$ 8,889	$ 11,182	$ 7,742	$ 4,014	$ 573	$ 573	$ -	$ 49,031
2015	$ 2,003	$ 1,716	$ 4,005	$ 3,576	$ 3,576	$ 4,720	$ 3,290	$ 3,004	$ 2,146	$ 1,144	$ 1,716	$ 1,860	$ 32,756
2016	$ 858	$ 644	$ 3,862	$ 3,218	$ 3,433	$ 6,651	$ 8,368	$ 5,793	$ 3,004	$ 429	$ 429	$ -	$ 36,690
2017	$ 1,774	$ 1,459	$ 4,978	$ 4,291	$ 4,434	$ 7,266	$ 7,553	$ 5,664	$ 3,290	$ 973	$ 1,316	$ 1,116	$ 44,113
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 73,572	$ 71,798	$100,805	$ 89,091	$ 88,677	$112,197	$120,793	$103,526	$ 83,463	$ 63,408	$ 67,783	$ 68,889	$1,044,000

Table 53

2023 Market Offer Revenue Allocation by LSE

LSE	**Declined System RA Volumes (MW)**	**2022 Revenues**
IOU	0	$ -
A	203	$ 488,116
B	53	$ 126,378
C	54	$ 128,852
D	125	$ 300,654
Total	434	$ 1,044,000

Table 54

2023 Market Price Benchmark Assumptions

MPBs	Local RA	System RA	Flex RA	RPS	Energy
2023	$5.50	$4.50	$3.50	$18.00	$22.00

Table 55
2023 Costs and Energy Revenues by Contract

Contract	Vintage	Contract Cost	Energy Value	Net Above Market Cost
1	CTC-Eligible	$ 14,716,800	$ (16,188,480)	$ (1,471,680)
2	CTC-Eligible	$ 4,599,000	$ (4,047,120)	$ 551,880
3	CTC-Eligible	$257,894,400	$(177,302,400)	$ 80,592,000
4	CTC-Eligible	$134,904,000	$ (84,796,800)	$ 50,107,200
5	2004-2009	$ 2,365,200	$ (1,156,320)	$ 1,208,880
6	2004-2009	$ 51,246,000	$ (4,509,648)	$ 46,736,352
7	2004-2009	$ 79,891,200	$ (14,646,720)	$ 65,244,480
8	2010	$ 22,776,000	$ (2,505,360)	$ 20,270,640
9	2011	$183,960,000	$ (16,188,480)	$167,771,520
10	2014	$ 66,225,600	$ (8,094,240)	$ 58,131,360
11	2015	$ 31,886,400	$ (5,010,720)	$ 26,875,680
12	2016	$ 18,396,000	$ (8,094,240)	$ 10,301,760
13	2017	$ 11,037,600	$ (5,396,160)	$ 5,641,440
14	2017	$ 5,739,552	$ (3,006,432)	$ 2,733,120
15	2017	$ 2,700,000	$ -	$ 2,700,000
16	2018	$ 48,000,000	$ -	$ 48,000,000
17	2020	$ 20,400,000	$ -	$ 20,400,000
18	2020	$ 4,950,000	$ -	$ 4,950,000
19	2020	$ 1,800,000	$ -	$ 1,800,000
Total		$963,487,752	$(350,943,120)	$612,544,632

Table 56

2023 Net Above Market Costs to be Recovered in PCIA Rates by Vintage ($)

Vintage	Contract Cost	Energy Value	Net Above Market Cost (Ratemaking Option 1)	RA Allocation Revenue	RA Market Offer Revenue	RPS Allocation Revenue	RPS Market Offer Revenue	Net Above Market Cost (Ratemaking Option 2)
CTC-Eligible	$ 412,114,200	$ (282,334,800)	$ 129,779,400	$ (1,483,388)	$ (190,703)	$ -	$ -	$ 128,105,309
2004-2009	$ 133,502,400	$ (20,312,688)	$ 113,189,712	$ (4,439,646)	$ (570,758)	$ (11,755,044)	$ (3,568,418)	$ 92,855,846
2010	$ 22,776,000	$ (2,505,360)	$ 20,270,640	$ (474,264)	$ (21,887)	$ (1,770,316)	$ (254,561)	$ 17,749,612
2011	$ 183,960,000	$ (16,188,480)	$ 167,771,520	$ (2,124,869)	$ (98,062)	$ (11,438,967)	$ (1,644,853)	$ 152,464,769
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
2014	$ 66,225,600	$ (8,094,240)	$ 58,131,360	$ (1,062,435)	$ (49,031)	$ (5,719,484)	$ (822,427)	$ 50,477,984
2015	$ 31,886,400	$ (5,010,720)	$ 26,875,680	$ (969,161)	$ (32,756)	$ (3,709,234)	$ (355,577)	$ 21,808,952
2016	$ 18,396,000	$ (8,094,240)	$ 10,301,760	$ (1,085,545)	$ (36,690)	$ (5,991,840)	$ (574,393)	$ 2,613,292
2017	$ 19,477,152	$ (8,402,592)	$ 11,074,560	$ (1,305,193)	$ (44,113)	$ (6,220,101)	$ (596,275)	$ 2,908,878
2018	$ 48,000,000	$ -	$ 48,000,000	$ -	$ -	$ -	$ -	$ 48,000,000
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
2020	$ 27,150,000	$ -	$ 27,150,000	$ (8,100,000)	$ -	$ -	$ -	$ 19,050,000
Total	$ 963,487,752	$ (350,943,120)	$ 612,544,632	$ (21,044,501)	$ (1,044,000)	$ (46,604,986)	$ (7,816,503)	$ 536,034,642

Table 57
2023 Illustrative PCIA Rate Calculations

Vintage	Net Above Market Cost (Ratemaking Option 1)	Net Above Market Cost (Ratemaking Option 2	Load (GWh)	Incremental Rate ($/kWh) (Ratemaking Option 1)	Incremental Rate ($/kWh) (Ratemaking Option 2)	Rate ($/kWh) (Ratemaking Option 1)	Rate ($/kWh) (Ratemaking Option 2)
CTC-Eligible	$ 129,779,400	$ 128,105,309	76,000	$ 0.001708	$ 0.001686	$ 0.001708	$ 0.001686
2004-2009	$ 113,189,712	$ 92,855,846	76,000	$ 0.001489	$ 0.001222	$ 0.003197	$ 0.002907
2010	$ 20,270,640	$ 17,749,612	66,000	$ 0.000307	$ 0.000269	$ 0.003504	$ 0.003176
2011	$ 167,771,520	$ 152,464,769	66,000	$ 0.002542	$ 0.002310	$ 0.006046	$ 0.005486
2012	$ -	$ -	66,000	$ -	$ -	$ 0.006046	$ 0.005486
2013	$ -	$ -	66,000	$ -	$ -	$ 0.006046	$ 0.005486
2014	$ 58,131,360	$ 50,477,984	66,000	$ 0.000881	$ 0.000765	$ 0.006927	$ 0.006251
2015	$ 26,875,680	$ 21,808,952	63,000	$ 0.000427	$ 0.000346	$ 0.007353	$ 0.006597
2016	$ 10,301,760	$ 2,613,292	63,000	$ 0.000164	$ 0.000041	$ 0.007517	$ 0.006639
2017	$ 11,074,560	$ 2,908,878	63,000	$ 0.000176	$ 0.000046	$ 0.007693	$ 0.006685
2018	$ 48,000,000	$ 48,000,000	63,000	$ 0.000762	$ 0.000762	$ 0.008455	$ 0.007447
2019	$ -	$ -	50,000	$ -	$ -	$ 0.008455	$ 0.007447
2020	$ 27,150,000	$ 19,050,000	50,000	$ 0.000543	$ 0.000381	$ 0.008998	$ 0.007828
Total	$ 612,544,632	$ 536,034,642					

Table 58

2023 Total Cost Responsibility - Ratemaking Option 1

LSE	Vintage	Annual Load (GWh)	Customer PCIA Rate Payments (Ratemaking Option 1)	IOU RA Revenue Payment to LSE	IOU RPS Revenue Payment to LSE	Net LSE & LSE Customer PCIA Cost Responsibility
IOU	2020	50,000	$ 449,883,667	$ -	$ -	$ 449,883,667
A	2004-2009	10,000	$ 31,969,620	$ (488,116)	$ (1,878,115)	$ 29,603,389
B	2014	3,000	$ 20,780,591	$ (126,378)	$ (1,470,715)	$ 19,183,498
C	2018	1,000	$ 8,454,673	$ (128,852)	$ -	$ 8,325,822
D	2018	12,000	$ 101,456,080	$ (300,654)	$ (4,467,674)	$ 96,687,752
			$ 612,544,632	$ (1,044,000)	$ (7,816,503)	$ 603,684,129

Table 59

2023 Total Cost Responsibility - Ratemaking Option 2

LSE	Vintage	Annual Load (GWh)	Customer PCIA Rate Payments (Ratemaking Option 2)	LSE RA Allocation Payment to IOU	LSE RPS Allocation Payment to IOU	Net LSE & LSE Customer PCIA Cost Responsibility
IOU	2020	50,000	$ 391,396,971	$ 18,555,821	$ 40,881,567	$ 450,834,359
A	2004-2009	10,000	$ 29,073,836	$ -	$ -	$ 29,073,836
B	2014	3,000	$ 18,753,622	$ 236,657	$ -	$ 18,990,279
C	2018	1,000	$ 7,446,939	$ -	$ 817,631	$ 8,264,571
D	2018	12,000	$ 89,363,273	$ 2,252,023	$ 4,905,788	$ 96,521,084
			$ 536,034,642	$ 21,044,501	$ 46,604,986	$ 603,684,129

Appendix I

RPS LONG-TERM ALLOCATION EXAMPLES

Example of Long-Term vs. Short-Term RPS Allocation Treatment

This Appendix provides a more detailed example regarding the treatment of long-term RPS energy attributes from an illustrative IOU's PCIA-eligible portfolio. This example leverages most of the same assumptions as the end-to-end example in Appendix H, but makes some minor modifications to demonstrate key aspects of long-term RPS treatment in the Co-Chairs' proposed RPS energy VAMO process. The following narrative serves as a guide to understand what takes place within each table or calculation and to provide additional context around how the results in each table are to be interpreted.

Table 1. **LSE Assumptions**

As with Table 1 of the end-to-end example, Table 1 in this Appendix presents the assumptions for each LSE. As this example only focuses upon the potential to accept long-term RPS allocations, only the annual load and LSE vintage is required for this example.

Table 2. **LSEs' Vintaged Annual Load Shares**

As in the end-to-end example, Table 2 calculates each LSE's vintaged annual (MWh) load share for this example.

Table 3. **LSEs' Vintaged Annual Load Share Percentages**

As in the end-to-end example, Table 3 translates Table 2 into percentages of annual vintage load.

Table 4. **Model IOU RPS Portfolio**

Table 4 presents this example's illustrative IOU portfolio of PCIA-eligible resources. In this example, only the RPS resources are identified. Most of the same contracts exist, but to distinguish the treatment of long-term RPS contract attribute preservation from short-term RPS contract credit, two additional short-term RPS contracts (*i.e.*, with less than 10 years in their original contract term) have been added. These contracts are identified as Contracts 6 and 9. Additionally, some of the term start dates have been updated.

Table 5. Contract-Specific Long-Term RPS Energy Production Forecast

The Co-Chairs propose that for an LSE to receive long-term RPS credit through an allocation, the underlying IOU contracts must have originally been long-term contracts. Thus, Table 5 calculates how much RPS energy is available in each delivery year only for the contracts that qualify as long-term contracts. Thus, Contracts 6 and 9 have no long-term RPS energy production in this table. The contracts' vintages are identified so that the forecasted long-term RPS generation can be summed by vintage in Table 6.

Table 6. Vintage-Specific Long-Term RPS Energy Production

Table 6 sums the long-term RPS energy available in each delivery year by vintage. This will be used in Table 7 to determine each LSE's eligible share of the PCIA-eligible RPS portfolio on the basis of their customers' departure date.

By reviewing this illustrative data for the 2004-2009 vintage, it can be seen that LSEs in that vintage would not be able to receive RPS allocations for a full 10 years, as the longest dated contract (Contract 2 from Tables 4 and 5) would cease deliveries in 2031 (the 9^{th} year of allocations from a January 1, 2023 implementation date). Similarly, if a 2010-vintaged LSE wished to take an allocation, their allocation would not fulfill a complete 10 years, as the longest dated contract (Contract 3) would expire on February 29, 2032, resulting in an allocation term of 9 years and 2 months. Ultimately, however, it is most complete to review the actual volumes that each LSE would be eligible to receive from the long-term PCIA-eligible RPS energy portfolio, as demonstrated in Table 7.

Table 7. Long-Term RPS Energy Allocation Eligibility

Table 7 illustrates the allocation volumes that each of the illustrative LSEs would be eligible to receive of the IOU's PCIA-eligible, long-term RPS energy. This table is calculated in the same manner as Table 21 in the end-to-end example from Appendix H.

It is helpful to review this table to determine the ability of an LSE to get long-term RPS credit, rather than Table 6, as later-vintaged LSEs will be eligible to receive allocations sourced from earlier-vintaged contracts. Here it is again clear that a 2004-2009 vintaged LSE (LSE A in this example) would not be eligible for an allocation that spans 10 years in length. Similarly, a 2010-vintaged LSE (LSE B) would not get a full 10 year allocation term. LSEs may find themselves in this situation as a result of the date upon which the RPS VAMO proposal is implemented. These LSEs still pay the same PCIA rates associated with the vintages they are eligible to take as an allocation as later-vintaged LSEs, but would not be able to claim long-term RPS credit by taking a long-term allocation.

Thus, the Co-Chairs have proposed that in the first RPS allocation election opportunity, LSEs that would not be able to take a 10-year allocation should be grandfathered into the long-term treatment of the IOU's underlying contracts. This would allow LSE A and B in this example to receive all of the forecasted energy production identified in Table 7 as long-term RPS energy, rather than solely as short-term RPS energy.

Outside of the single grandfathering opportunity, LSEs may only receive long-term credit if they elect their long-term allocation when the remaining term of the longest dated, non-evergreen and non-UOG, contract has at least 10 or more years remaining in its contract term. Thus, LSE C may, in each annual election opportunity, elect to accept a short-term allocation or to decline its allocations, in each case electing to not receive long-term RPS procurement credit for such delivery years, but still preserve its ability to enter into a long-term allocation as long as it makes a long-term election by the 2026 elections for 2027-2037 delivery term for LSE C. For clarity, in this case, LSE C would only receive long-term RPS credit for 2027-2037 and would have foregone long-term credit prior to such delivery years. LSE D would be in a similar situation and could make a long-term election as late as 2028 for the 2029-2039 delivery years to receive long-term credit for that specific allocation term.

Table 1

LSE Assumptions

LSE	Vintage	Annual Load (GWh)
IOU	2020	50,000
A	2004-2009	10,000
B	2010	3,000
C	2014	1,000
D	2018	12,000

Table 2

LSE's Vintaged Annual Load Shares

		Annual Vintaged Loads (GWh)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
A	2004-2009	10,000	10,000	-	-	-	-	-	-	-	-	-	-	-
B	2010	3,000	3,000	3,000	-	-	-	-	-	-	-	-	-	-
C	2014	1,000	1,000	1,000	1,000	1,000	1,000	1,000	-	-	-	-	-	-
D	2018	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	-	-
Total		76,000	76,000	66,000	63,000	63,000	63,000	63,000	62,000	62,000	62,000	62,000	50,000	50,000

Table 3

LSE's Vintaged Annual Load Share Percentages

		Annual Vintaged Load Shares (%)												
LSE	**Vintage**	**CTC-Eligible**	**2004-2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
IOU	2020	66%	66%	76%	79%	79%	79%	79%	81%	81%	81%	81%	100%	100%
A	2004-2009	13%	13%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
B	2010	4%	4%	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
C	2014	1%	1%	2%	2%	2%	2%	2%	0%	0%	0%	0%	0%	0%
D	2018	16%	16%	18%	19%	19%	19%	19%	19%	19%	19%	19%	0%	0%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 4
Model IOU RPS Portfolio

Contract #	Vintage	Online Date	Term (Years)	Termination Date	Technology	Installed AC Capacity (MW)	Expected Annual Energy Production (GWh)
1	2004-2009	1/1/2011	20	12/31/2030	Wind	90	205
2	2004-2009	7/1/2011	20	6/30/2031	Geothermal	100	666
3	2010	3/1/2012	20	2/29/2032	Wind	50	114
4	2011	1/1/2014	20	12/31/2033	Solar	300	736
5	2014	1/1/2018	20	12/31/2037	Solar	150	368
6	2014	3/1/2019	5	2/28/2024	Wind	120	273
7	2015	7/1/2018	15	6/30/2033	Wind	100	228
8	2016	1/1/2020	15	12/31/2034	Solar	150	368
9	2016	9/1/2018	8	8/31/2026	Solar	90	221
10	2017	1/1/2020	20	12/31/2039	Solar	100	245
11	2017	1/1/2019	10	12/31/2028	Wind	60	137

Table 5

Contract-Specific Long-Term RPS Energy Production Forecast (GWh)

Contract #	Vintage	Term (Years)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	2004-2009	20	205	205	205	205	205	205	205	205	0	0	0	0	0	0	0	0	0	0
2	2004-2009	20	666	666	666	666	666	666	666	666	333	0	0	0	0	0	0	0	0	0
3	2010	20	114	114	114	114	114	114	114	114	114	19	0	0	0	0	0	0	0	0
4	2011	20	736	736	736	736	736	736	736	736	736	736	736	0	0	0	0	0	0	0
5	2014	20	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	0	0	0
6	2014	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	2015	15	228	228	228	228	228	228	228	228	228	228	114	0	0	0	0	0	0	0
8	2016	15	368	368	368	368	368	368	368	368	368	368	368	368	0	0	0	0	0	0
9	2016	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	2017	20	245	245	245	245	245	245	245	245	245	245	245	245	245	245	245	245	245	0
11	2017	10	137	137	137	137	137	137	0	0	0	0	0	0	0	0	0	0	0	0
Total			3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,391	1,963	1,831	981	613	613	613	245	245	-

Table 6

Vintage-Specific Long-Term RPS Energy Production (GWh)

Vintage	Allocation Year / Delivery Year	1 2023	2 2024	3 2025	4 2026	5 2027	6 2028	7 2029	8 2030	9 2031	10 2032	11 2033	12 2034	13 2035	14 2036	15 2037	16 2038	17 2039	18 2040
CTC-Eligible		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2004-2009		871	871	871	871	871	871	871	871	333	0	0	0	0	0	0	0	0	0
2010		114	114	114	114	114	114	114	114	114	19	0	0	0	0	0	0	0	0
2011		736	736	736	736	736	736	736	736	736	736	736	0	0	0	0	0	0	0
2012		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2013		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014		368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	0	0	0
2015		228	228	228	228	228	228	228	228	228	228	114	0	0	0	0	0	0	0
2016		368	368	368	368	368	368	368	368	368	368	368	368	0	0	0	0	0	0
2017		382	382	382	382	382	382	245	245	245	245	245	245	245	245	245	245	245	0
2018		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,391	1,963	1,831	981	613	613	613	245	245	-

Table 7

Long-Term RPS Energy Allocation Eligibility (GWh)

	Allocation Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
LSE	**Vintage**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
IOU	2020	2,324	2,324	2,324	2,324	2,324	2,324	2,213	2,213	1,859	1,568	1,462	787	490	490	490	198	198	-
A	2004-2009	115	115	115	115	115	115	115	115	44	-	-	-	-	-	-	-	-	-
B	2010	40	40	40	40	40	40	40	40	18	1	-	-	-	-	-	-	-	-
C	2014	31	31	31	31	31	31	31	31	24	18	18	6	6	6	6	-	-	-
D	2018	558	558	558	558	558	558	531	531	446	376	351	189	118	118	118	47	47	-
Total		3,066	3,066	3,066	3,066	3,066	3,066	2,929	2,929	2,391	1,963	1,831	981	613	613	613	245	245	-

Appendix J

PROPOSED IMPLEMENTATION TIMELINES

Legend
BPP
ERRA
GHG-Free Term Sheet & Advice Letter
IOU Procurement / Sales Activity
IRP
PCIA OIR
RA OIR
RA Process
RPS OIR

Indicative GHG-Free Energy Voluntary Allocation Implementation Timeline					
Proceeding	**Milestone**	**Rough Date**	**Indicative Timeline**	**Delivery Year**	**Impact**
PCIA OIR	File Final Report		2/21/2020	All	
PCIA OIR	Opening Comments		3/13/2020	All	
GHG-Free Term Sheet & Advice Letter	SCE to file Interim GHG-Free Allocation Term Sheet & Advice Letter for Approval	Within 30 days of filing Final Report	3/22/2020	2020-2022	Request approval for interim GHG-free energy voluntary allocation approach on basis of actual load shares
PCIA OIR	Reply Comments		3/27/2020	All	
GHG-Free Term Sheet & Advice Letter	Receive Approval for GHG-free energy voluntary allocations	3 months after filing Advice Letter	6/20/2020	2020-2022	Enable interim GHG-free energy voluntary allocation approach
GHG-Free Term Sheet & Advice Letter	LSEs submit GHG-free energy allocation elections, pending approval of Advice Letter	Approval of Advice Letter + 30 days	8/19/2020	2020	LSEs submit allocation elections, to permit rapid implementation of allocations
GHG-Free Term Sheet & Advice Letter	Commence interim GHG-free energy allocations and energy scheduling for 2020	Next month after LSEs submit elections	9/1/2020	2020	Commence scheduling energy for allocations
PCIA OIR	WG 3 Proposed Decision	Q3 2020	9/1/2020	All	
PCIA OIR	Opening Comments on PD	PD + 20 days	9/21/2020	All	
PCIA OIR	Reply Comments on PD	Opening Comments + 5 days	9/26/2020	All	
PCIA OIR	WG 3 Decision	Reply Comments + 1 week	10/3/2020	All	
GHG-Free Term Sheet & Advice Letter	LSEs submit GHG-free energy allocation elections for 2021	November 2020	11/15/2020	2021	LSEs submit allocation elections for 2021
RA OIR	Integrate PCIA WG3 Decision into 2021 RA OIR Scoping Memo	December 2020	12/1/2020	2023	Introduce discussion of vintaged annual load forecasting methodologies into RA OIR Scoping Memo
BPP	Update BPP via Tier 2 AL	WG 3 Decision + 90 days	1/1/2021	2023	Request approval to conduct WG 3's proposed voluntary allocations
GHG-Free Term Sheet & Advice Letter	Commence interim GHG-free energy allocations and energy scheduling for 2021	January 1, 2021	1/1/2021	2021	Commence scheduling energy for allocations
BPP	Receive Approval of BPP Update	BPP AL + 90 days	4/1/2021	2023	Receive approval to conduct WG 3's proposed voluntary allocations
ERRA	ERRA Forecast Application	May 2021	5/31/2021	2022	Publish forecasted PCIA-eligible GHG-free energy volumes and vintaged annual loads
RA OIR	Decision on RA OIR implementing changes for 2022+ filing(s)	June 2021	6/1/2021	2023	Rule upon vintaged annual load forecasting methodologies
GHG-Free Term Sheet & Advice Letter	LSEs submit GHG-free energy allocation elections for 2022	November 2021	11/15/2021	2022	LSEs submit allocation elections for 2022
ERRA	Update to ERRA Forecast Application	November 2021	11/15/2021	2022	Publish forecasted volumes and vintaged annual loads for 2022.
GHG-Free Term Sheet & Advice Letter	Commence interim GHG-free energy allocations and energy scheduling for 2022	January 1, 2022	1/1/2022	2022	Commence scheduling energy for allocations

IRP	Proposed Decision on RSP and Filing Requirements	February 2022	2/1/2022	All	Gives guidance on forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for Clean Net Short credit, etc.
IRP	LSEs submit updated multi-year load forecasts for IRP	Late-February 2022	2/28/2022	All	Establishes basis for vintaged, annual load shares for allocation of Clean Net Short credit
IRP	Decision on RSP	March 2022	3/15/2022	All	Rules upon forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for Clean Net Short credit, etc.
RA Process	LSEs submit vintaged, historical loads to ED & CEC	March 2022	3/15/2022	2023	Commence process of determining vintaged, annual load shares
RA Process	LSEs submit vintaged load forecasts for 2023 to ED & CEC	April 2022	4/19/2022	2023	Forecast annual load shares for 2023 allocations
ERRA	ERRA Forecast Application	May 2022	5/31/2022	2023	Publish forecasted PCIA-eligible GHG-free energy volumes and vintaged annual loads
IRP	LSE IRP Filings Due	July 2022	7/1/2022	All	LSEs include eligible allocation shares towards IRP procurement requirements
RA Process	ED publishes preliminary RA obligations, load shares, and PCIA allocations	July 2022	7/26/2022	2023	Establish preliminary allocations for 2023
RA Process	Final date for LSEs to file revised forecasts for 2023 with ED & CEC	August 2022	8/16/2022	2023	Update assumptions for calculating allocation shares
IOU Procurement / Sales Activity	LSEs submit System and Flex RA, and RPS and GHG-free energy allocation elections	Within 30 days of publication of preliminary forecasted, vintaged, annual load shares	8/25/2022	2023	Determine allocation elections
RA Process	ED publishes final RA obligations, vintaged load shares, and PCIA allocations	September 2022	9/20/2022	2023	Establish final allocation shares for 2023
ERRA	Update to ERRA Forecast Application	November 2022	11/15/2022	2023	Publish forecasted volumes and vintaged annual loads for 2023.
IOU Procurement / Sales Activity	Commence full RPS and GHG-free energy allocations and energy scheduling for 2023	January 1, 2023	1/1/2023	2023	Commence scheduling energy for allocations
ERRA	ERRA Forecast Application	May 2023	5/31/2023	2024	Publish forecasted PCIA-eligible GHG-free energy volumes and vintaged annual loads
ERRA	Update to ERRA Forecast Application	November 2023	11/15/2023	2024	Publish forecasted volumes and vintaged annual loads for 2023.
IOU Procurement / Sales Activity	IOUs report volumes and resources sourced for RPS and GHG-free energy deliveries for Power Content Label reporting	By Q2 following delivery year	4/1/2024	2023	Facilitate Power Content Label reporting
ERRA	ERRA Review of Operations Application	April 2024	4/15/2024	2023	Publish actual volumes, costs, and revenues for 2023.

Indicative RPS Energy VAMO Implementation Timeline					
Proceeding	**Milestone**	**Rough Date**	**Indicative Timeline**	**Delivery Year**	**Impact**
PCIA OIR	File Final Report		2/21/2020	All	
PCIA OIR	Opening Comments		3/13/2020	All	
PCIA OIR	Reply Comments		3/27/2020	All	
PCIA OIR	WG 3 Proposed Decision	Q3 2020	9/1/2020	All	
PCIA OIR	Opening Comments on PD	PD + 20 days	9/21/2020	All	
PCIA OIR	Reply Comments on PD	Opening Comments + 5 days	9/26/2020	All	
PCIA OIR	WG 3 Decision	Reply Comments + 1 week	10/3/2020	All	Approval of WG 3 Decision
RA OIR	Integrate PCIA WG3 Decision into 2021 RA OIR Scoping Memo	December 2020	12/1/2020	All	Introduce discussion of advancing RA process timelines and vintaged annual load forecasting methodologies into RA OIR Scoping Memo
RPS OIR	RPS Procurement Ruling/Scoping	March/April	4/1/2021	All	Opening of OIR to update RPS Procurement Plan for VAMO implementation
ERRA	ERRA Forecast Application	May 2021	5/31/2021	2023	Publish forecasted PCIA-eligible RPS volumes
RA OIR	Decision on RA OIR implementing changes for 2022+ filing(s)	June 2021	6/1/2021	All	Rule upon updated timelines for RA process and vintaged annual load forecasting methodologies
RPS OIR	File RPS Procurement Plan	June/July	6/15/2021	All	Incorporate mechanisms and processes for VAMO for RPS energy
RPS OIR	File updates to RPS Procurement Plan	August/September	8/15/2021	All	File updates to request for approval of VAMO processes
RPS OIR	RPS Procurement Plan PD	Mid- to Late-November	11/15/2021	All	PD ruling upon proposed methodology for VAMO implementation
ERRA	Update to ERRA Forecast Application	November 2021	11/15/2021	2023	Publish forecasted PCIA-eligible RPS volumes
RPS OIR	Final Decision on RPS Procurement Plan	PD on RPS Procurement Plan + 30 days	12/15/2021	All	Final Decision ruling upon proposed VAMO implementation
IRP	Proposed Decision on RSP and Filing Requirements	February 2022	2/1/2022	All	Gives guidance on forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for Clean Net Short credit, etc.
IRP	LSEs submit updated multi-year load forecasts for IRP	Late-February 2022	2/28/2022	All	Establishes basis for vintaged, annual load shares for allocation of Clean Net Short credit

IRP	Decision on RSP	March 2022	3/15/2022	All	Rules upon forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for Clean Net Short credit, etc.
RA Process	LSEs submit vintaged, historical loads to ED & CEC	March 2022	3/15/2022	2023	Commence process of determining vintaged, annual load shares
RA Process	LSEs submit vintaged load forecasts for 2023 to ED & CEC	April 2022	4/19/2022	2023	Forecast annual load shares for 2023 allocations
ERRA	ERRA Forecast Application	May 2022	5/31/2022	2023	Publish forecasted PCIA-eligible RPS volumes
IRP	LSE IRP Filings Due	July 2022	7/1/2022	All	LSEs include eligible allocation shares towards IRP procurement requirements
RA Process	ED publishes preliminary RA obligations, load shares, and PCIA allocations	July 2022	7/26/2022	2023	Establish preliminary allocations
RA Process	Final date for LSEs to file revised forecasts for 2023 with ED & CEC	August 2022	8/16/2022	2023	Update assumptions for calculating allocation shares
IOU Procurement / Sales Activity	LSEs submit System and Flex RA, and RPS and GHG-free energy allocation elections	Within 30 days of publication of preliminary forecasted, vintaged, annual load shares	8/25/2022	2023	Determine allocation elections
RA Process	ED publishes final RA obligations, vintaged load shares, and PCIA allocations	September 2022	9/20/2022	2023	Establish final allocation shares for 2023
IOU Procurement / Sales Activity	IOUs launch RPS Market Offer	Within 1 week of publication of final, forecasted, vintaged annual load shares	9/27/2022	2023	Publish RFO instructions and inform the market of estimates of RPS energy volumes for sale
IOU Procurement / Sales Activity	CAM Review of RPS Selections	Coincident with Completion of RPS Market Offer	10/18/2022	2023	Review proposed RPS Market Offer sales with CAM group
IOU Procurement / Sales Activity	Complete RPS Market Offer	3 weeks start to finish	10/18/2022	2023	Select offers and sign contracts
ERRA	Update to ERRA Forecast Application	November 2022	11/15/2022	2023	Publish forecasted volumes, vintaged annual loads, and forecast MPB for 2023.
IOU Procurement / Sales Activity	Commence full RPS and GHG-free energy allocations and energy scheduling for 2023	January 1, 2023	1/1/2023	2023	

IOU Procurement / Sales Activity	Payment owed for allocations and sales	~20 days following close of compliance month	2/20/2023	2023	LSES accepting allocations or sales to pay for delivered RPS energy
ERRA	ERRA Forecast Application	May 2023	5/31/2023	2024	Publish forecasted PCIA-eligible RPS volumes
IOU Procurement / Sales Activity	Transfer RECs for each flow month	Within 120 days after flow month	5/31/2023	2023	Transfer RECs to parties accepting allocations or purchasing in Market Offer
ERRA	Update to ERRA Forecast Application	November 2023	11/15/2023	2023-24	Publish actual volumes and true-up MPB for 2023. Publish forecasted volumes, vintaged annual loads, and forecast MPB for 2024.
IOU Procurement / Sales Activity	True-Up Payment Owed for Allocations	December 2023	12/15/2023	2023	LSEs accepting allocations to pay true-up payment relating to difference between forecast and actual MPB
IOU Procurement / Sales Activity	IOUs report volumes and resources sourced for RPS and GHG-free energy deliveries for Power Content Label reporting	By Q2 following delivery year	4/1/2024	2023	Facilitate Power Content Label reporting
ERRA	ERRA Review of Operations Application	April 2024	4/15/2024	2023	Publish actual volumes, costs, and revenues for 2023.

Indicative System and Flex RA VAMO Implementation Timeline					
Proceeding	Milestone	Rough Date	Indicative Timeline	Compliance Year	Impact
PCIA OIR	File Final Report		2/21/2020	All	
PCIA OIR	Opening Comments		3/13/2020	All	
PCIA OIR	Reply Comments		3/27/2020	All	
PCIA OIR	WG 3 Proposed Decision	Q3 2020	9/1/2020	All	
PCIA OIR	Opening Comments on PD	PD + 20 days	9/21/2020	All	
PCIA OIR	Reply Comments on PD	Opening Comments + 5 days	9/26/2020	All	
PCIA OIR	WG 3 Decision	Reply Comments + 1 week	10/3/2020	All	
RA OIR	Integrate PCIA WG3 Decision into 2021 RA OIR Scoping Memo	December 2020	12/1/2020	2023	Introduce discussion of advancing RA process timelines; vintaged peak load forecasting methodologies; and PCIA Showing implementation
BPP	Update BPP via Tier 2 AL	WG 3 Decision + 90 days	1/1/2021	2023	Request approval to conduct voluntary allocations and Market Offer sales
BPP	Receive Approval of BPP Update	BPP AL + 90 days	4/1/2021	2023	Receive approval to conduct voluntary allocations and Market Offer sales
ERRA	ERRA Forecast Application	May 2021	5/31/2021	2023	Publish forecasted PCIA-eligible System/Flex RA volumes
RA OIR	Decision on RA OIR implementing changes for 2022+ filing(s)	June 2021	6/1/2021	2023	Rule upon updated timelines for RA process; vintaged coincident peak-load forecasting methodologies; and PCIA Showing
ERRA	Update to ERRA Forecast Application	November 2021	11/15/2021	2023	Publish forecasted PCIA-eligible System/Flex RA volumes
IRP	Proposed Decision on RSP and Filing Requirements	February 2022	2/1/2022	All	Gives guidance on forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for RA procurement credit, etc.
IRP	LSEs submit updated multi-year load forecasts for IRP	Late-February 2022	2/28/2022	All	Establishes basis for vintaged, coincident, peak-load shares for allocation of RA credit

IRP	Decision on RSP	March 2022	3/15/2022	All	Rules upon forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for RA procurement credit, etc.
RA Process	LSEs submit vintaged, historical loads to ED & CEC	March 2022	3/15/2022	2023	Commence process of determining vintaged, coincident peak-load shares
IOU Procurement / Sales Activity	LSEs submit spring RA allocation elections to IOUs	April 2022	4/1/2022	2023	Determine System/Flex RA volumes to be sold in spring Market Offer
IOU Procurement / Sales Activity	IOUs launch spring RA Market Offer process	April 2022	4/19/2022	2023	Inform market of System/Flex RA volumes to be offered
RA Process	LSEs submit vintaged load forecasts for 2023 to ED & CEC	April 2022	4/19/2022	2023	Forecast peak-loads for 2023
IOU Procurement / Sales Activity	CAM review of selections	Coincident with completion of Market Offer	5/3/2022	2023	Review offer selections with CAM
IOU Procurement / Sales Activity	IOUs complete spring RA Market Offer process	2 weeks after launch	5/3/2022	2023	Execute System/Flex RA sales agreements
ERRA	ERRA Forecast Application	May 2022	5/31/2022	2023	Publish forecasted PCIA-eligible System/Flex RA volumes
IRP	LSE IRP Filings Due	July 2022	7/1/2022	All	LSEs include eligible allocation shares towards IRP procurement requirements
RA Process	IOUs submit CAM and PCIA Showing RA volumes to ED	July 2022	7/12/2022	2023	Volumes to be allocated in PCIA Showing for 2023 compliance year are frozen, subject to NQC/EFC adjustment
RA Process	ED publishes preliminary RA obligations, load shares, and PCIA allocations	July 2022	7/26/2022	2023	Establish preliminary allocations
RA Process	Final date for LSEs to file revised forecasts for 2023 with ED & CEC	August 2022	8/16/2022	2023	Update assumptions for calculating allocation shares

IOU Procurement / Sales Activity	LSEs submit System and Flex RA, and RPS and GHG-free energy allocation elections	Within 30 days of publication of preliminary forecasted, vintaged, annual load shares	8/25/2022	2023	Determine LSE elections and rough allocation volumes
RA Process	CAISO updates NQC/EFC	September 2021	9/6/2022	2023	Finalize total PCIA-eligible System/Flex RA volumes available for allocation
IOU Procurement / Sales Activity	IOUs launch fall RA Market Offer process	September 2022 1 week after CAISO NQC/EFC Updates	9/13/2022	2023	Inform market of System/Flex RA volumes to be offered
RA Process	ED publishes final RA obligations, vintaged load shares, and PCIA allocations	September 2022	9/20/2022	2023	Establish final allocations for 2023
IOU Procurement / Sales Activity	CAM review of System/Flex RA selections	Coincident with completion of System/Flex RA Market Offer	10/4/2022	2023	Review offer selections with CAM
IOU Procurement / Sales Activity	IOUs complete fall RA Market Offer process	October 2022 2 weeks after Year-Ahead updates	10/4/2022	2023	Sell unallocated System/Flex RA volumes and re-allocate unsold volumes
RA Process	Year-Ahead RA filing due to ED & CAISO	October 31, 2021	10/31/2022	2023	Allocations are shown for LSEs accepting allocations or buying sold PCIA Showing RA capacity
ERRA	Update to ERRA Forecast Application	November 2022	11/15/2022	2023	Publish shown System/Flex RA volumes, vintaged coincident peak-loads, and forecast MPBs for 2023.
IOU Procurement / Sales Activity	Payment owed for allocations and sales	~20 days following close of compliance month	2/20/2023	2023	LSES accepting allocations or sales to pay for shown System/Flex RA
ERRA	ERRA Forecast Application	May 2023	5/31/2023	2024	Publish forecasted PCIA-eligible System/Flex RA volumes
ERRA	Update to ERRA Forecast Application	November 2023	11/15/2023	2023-24	Publish true-up MPB for 2023. Publish shown System/Flex RA volumes, vintaged coincident peak-loads, and forecast MPBs for 2024.
IOU Procurement / Sales Activity	True-Up Payment Owed for Allocations	December 2023	12/15/2023	2023	LSEs accepting allocations to pay true-up payment relating to difference between forecast and actual MPB
ERRA	ERRA Review of Operations Application	April 2024	4/15/2024	2023	Publish actual volumes, costs, and revenues for 2023.

Indicative Local RA Allocation Implementation Timeline					
Proceeding	**Milestone**	**Rough Date**	**Indicative Timeline**	**Compliance Year**	**Impact**
PCIA OIR	File Final Report		2/21/2020	All	
PCIA OIR	Opening Comments		3/13/2020	All	
PCIA OIR	Reply Comments		3/27/2020	All	
PCIA OIR	WG 3 Proposed Decision	Q3 2020	9/1/2020	All	
PCIA OIR	Opening Comments on PD	PD + 20 days	9/21/2020	All	
PCIA OIR	Reply Comments on PD	Opening Comments + 5 days	9/26/2020	All	
PCIA OIR	WG 3 Decision	Reply Comments + 1 week	10/3/2020	All	
RA OIR	Integrate PCIA WG3 Decision into 2021 RA OIR Scoping Memo	December 2020	12/1/2020	2024-25	Introduce discussion of vintaged peak load forecasting methodologies and PCIA Showing implementation
BPP	Update BPP via Tier 2 AL	WG 3 Decision + 90 days	1/1/2021	2024-25	Request approval to conduct allocations
BPP	Receive Approval of BPP Update	BPP AL + 90 days	4/1/2021	2024-25	Receive approval to conduct allocations
ERRA	ERRA Forecast Application	May 2021	5/31/2021	2024-25	Publish forecasted PCIA-eligible Local RA volumes
RA OIR	Decision on RA OIR implementing changes for 2022+ filing(s)	June 2021	6/1/2021	2024-25	Rule upon vintaged coincident peak-load forecasting methodologies and PCIA Showing
ERRA	Update to ERRA Forecast Application	November 2021	11/15/2021	2024-25	Publish forecasted PCIA-eligible Local RA volumes
IRP	Proposed Decision on RSP and Filing Requirements	February 2022	2/1/2022	All	Gives guidance on forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for RA procurement credit, etc.

IRP	LSEs submit updated multi-year load forecasts for IRP	Late-February 2022	2/28/2022	All	Establishes basis for vintaged, coincident, peak-load shares for allocation of RA credit
IRP	Decision on RSP	March 2022	3/15/2022	All	Rules upon forecasting methodologies to be used for treatment of PCIA allocations in IRP, specific implementation mechanics for RA procurement credit, etc.
RA Process	LSEs submit vintaged, historical loads to ED & CEC	March 2022	3/15/2022	2024-25	Commence process of determining vintaged, coincident peak-load shares
RA Process	LSEs submit vintaged load forecasts for 2023 to ED & CEC	April 2022	4/19/2022	2024-25	Forecast peak-loads for 2023, which will be applied to 2024-25
ERRA	ERRA Forecast Application	May 2022	5/31/2022	2024-25	Publish forecasted PCIA-eligible Local RA volumes
IRP	LSE IRP Filings Due	July 2022	7/1/2022	All	LSEs include eligible allocation shares towards IRP procurement requirements
RA Process	IOUs submit CAM and PCIA Showing RA volumes to ED	July 2022	7/12/2022	2024-25	Volumes to be allocated for 2022 filing year in PCIA Showing are frozen, subject to NQC adjustment
RA Process	ED publishes preliminary RA obligations, load shares, and PCIA allocations	July 2022	7/26/2022	2024-25	Establish preliminary allocations
RA Process	Final date for LSEs to file revised forecasts for 2023 with ED & CEC	August 2022	8/16/2022	2024-25	Update assumptions for calculating allocation shares
RA Process	CAISO updates NQC/EFC	September 2021	9/6/2022	2024-25	Finalize total PCIA-eligible Local RA volumes available for allocation
RA Process	ED publishes final RA obligations, vintaged load shares, and PCIA allocations	September 2022	9/20/2022	2024-25	Establish final allocations for 2024-25

RA Process	Year-Ahead RA filing due to ED & CAISO	October 31, 2021	10/31/2022	2024-25	Allocations are shown for LSEs accepting allocations or buying PCIA Showing Local RA capacity sold in secondary market
ERRA	Update to ERRA Forecast Application	November 2022	11/15/2022	2024-25	Publish shown Local RA volumes and vintaged coincident peak-loads for 2024-25.
ERRA	ERRA Forecast Application	May 2023	5/31/2023	2024-26	Publish forecasted PCIA-eligible Local RA volumes
ERRA	Update to ERRA Forecast Application	November 2023	11/15/2023	2024-26	Publish shown Local RA volumes and forecasted, vintaged coincident peak-loads for 2024-26.

Appendix K

LIST OF ACRONYMS

List of Acronyms

AB – Assembly Bill

ALJ – Administrative Law Judge

AReM – Alliance for Retail Energy Markets

AWEA – American Wind Energy Association of California

BPP – Bundled Procurement Plan

CAISO – California Independent System Operator

Cal PA – Public Advocates Office

CalCCA – California Association of Community Choice Aggregators

CAM – Cost Allocation Mechanism

CCA – Community Choice Aggregator

CEC – California Energy Commission

CLECA – California Large Energy Consumers Association

Commercial – Commercial Energy

CNS – Clean Net Short

CPE – Central Procurement Entity

CPM – Capacity Procurement Mechanism

CPUC or Commission – California Public Utilities Commission

CTC – Competition Transition Charge

CUE – Coalition of California Utility Employees

D. – Decision

DA – Direct Access

DACC – Direct Access Customer Coalition

DR – Demand Response

ED – CPUC's Energy Division

EFC – Effective Flexible Capacity

ERRA – Energy Resource Recovery Account

ESP – Energy Service Provider

FERC – Federal Energy Regulatory Commission

FPP – Fuel & Purchased Power

GHG – Greenhouse Gas

GRC – General Rate Case

Guide – Procurement Process Reference Guide

IE – Independent Evaluator

IOU – Investor Owned Utility

IRP – Integrated Resources Plan

kW – kilowatt

kWh – kilowatt-hour

LSA – Large-Scale Solar Association

LSE – Load Serving Entity

mo – month

MPB – Market Price Benchmark

MW – megawatt

MWh – megawatt-hour

NDA – Non-Disclosure Agreement

NQC – Net Qualifying Capacity

O&M – Operations and Maintenance

OIR – Order Instituting Rulemaking

PABA – Portfolio Allocation Balancing Account

PAM – Portfolio Allocation Mechanism

PCC – Portfolio Content Category

PCIA – Power Charge Indifference Amount, including the CTC

PCL – Power Content Label

PG&E – Pacific Gas & Electric

POC – Protect Our Communities Foundation

PPA – Power Purchase Agreement

PRG – Peer Review Group

PSDP – CEC's Power Source Disclosure Program

Q – Quarter (*i.e.,* 3 months of a calendar year)

QCR – Quarterly Compliance Review

NDA – Non-Disclosure Agreement

NQC – Net Qualifying Capacity

R. – Rulemaking

RA – Resource Adequacy

RAAIM – Resource Adequacy Availability Incentive Mechanism

REC – Renewable Energy Credit

RFI – Request for Interest

RPS – Renewables Portfolio Standard

RSP – Reference System Plan in IRP

SCE – Southern California Edison

SDG&E – San Diego Gas & Electric

Shell – Shell Energy

SJCE – San Jose Clean Energy

TAC – Transmission Access Charge

UCAN – The Utilities Consumers' Action Network

UCAP – Unforced Capacity Availability Protocol

UOG – Utility-Owned Generation

VAAC – Voluntary Allocation and Auction Clearinghouse

VAMO – Voluntary Allocation and Market Offer

WG – Working Group in Phase 2 of R.17-06-026

WREGIS – Western Renewable Generation Information System

MARCH FILINGS

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

Order Instituting Rulemaking to Implement Senate Bill No. 1488 (2004 Cal. Stats., Ch. 690 (Sept. 22, 2004)) Relating to Confidentiality of Information.	R.05-06-040

REPLY TO JOINT RESPONSE OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND THE UTILITY REFORM NETWORK TO CALIFORNIA COMMUNITY CHOICE ASSOCIATION PETITION FOR MODIFICATION OF DECISION D.06-06-066 AS AMENDED BY DECISIONS D.07-05-032, D.06-12-030, AND D.08-04-023

Evelyn Kahl
General Counsel
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
415.254.5454
regulatory@cal-cca.org

Ann Springgate
Buchalter, A Professional Corporation
55 Second Street
Suite 1700
San Francisco, CA 94105
415.227.0900
aspringgate@buchalter.com

Counsel to the
California Community Choice Association

March 9, 2020

TABLE OF CONTENTS

Page

TABLE OF AUTHORITIES

Page(s)

Statutes

CPUC Rules

CPUC Decisions

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

Order Instituting Rulemaking to Implement Senate Bill No. 1488 (2004 Cal. Stats., Ch. 690 (Sept. 22, 2004)) Relating to Confidentiality of Information.	R.05-06-040

REPLY TO JOINT RESPONSE OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND THE UTILITY REFORM NETWORK TO CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PETITION FOR MODIFICATION OF DECISION D.06-06-066 AS AMENDED BY DECISIONS D.07-05-032, D.06-12-030, AND D.08-04-023

Pursuant to Rule 16.4 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), the California Community Choice Association (CalCCA)[1] hereby submits this reply to the joint response of San Diego Gas & Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company (Joint Utilities) and to the response of The Utility Reform Network (TURN) to CalCCA's Petition for Modification (Petition) of Decision (D.) 06-06-066 as amended by D.07-05-032, D.06-12-030, and D.08-04-023 (Decision). By email dated February 26, 2020, Administrative Law Judge

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, Clean Power Alliance, Clean Power SF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

Yacknin authorized the filing of this reply and set the deadline for replies as March 9, 2020. This reply is timely filed.

I. INTRODUCTION AND EXECUTIVE SUMMARY

The Petition seeks to clarify that sensitive community choice aggregator (CCA) market information will be kept confidential consistent with the Electric Service Provider (ESP) matrix adopted in D.06-06-066.[2] Until contract price information is publicly disclosed much more rapidly for all Load Serving Entities (LSEs), CCAs must be allowed to participate in the energy market on an equal basis.

The Petition further seeks clarification regarding the interaction between the California Public Records Act[3] (PRA or Act) and the confidentiality matrix. TURN agrees with CalCCA that D.06-06-066 "should be modified to identify a specific matrix for CCAs in order to promote consistency across proceedings."[4] The Joint Utilities agree in their Response "that there exists a need for clarification of the applicability of the Commission's procurement confidentiality rules to CCAs."[5] While TURN and the Joint Utilities agree that action should be taken regarding confidentiality of CCA data, they disagree with CalCCA's proposed modifications.

---

2 Petition at 7.

3 CAL. GOV'T CODE §6250 *et seq.*

4 Response of The Utility Reform Network to the California Community Choice Association Petition for Modification of Decision 06-06-066 as amended by Decisions 07-05-032, 06-12-030, and 08-04-023, February 20, 2020, (TURN Response) at 1.

5 Joint Response of San Diego Gas & Electric Company (U 902-E), Pacific Gas and Electric Company (U 39-E) and Southern California Edison Company (U 338-E) to California Community Choice Association Petition for Modification of Decision 06-06-066 as amended by Decisions 07-05-032, 06-12-030, and 08-04-023, February 20, 2020, (Joint Utilities Response) at 6.

CalCCA requested the Decision be modified to make clear that "CCAs will make data available in accordance with the California Public Records Act."[6] TURN characterizes CalCCA's requested modifications as an attempt "to prevent Non-Market Participants (NMPs) from having access, pursuant to a protective order, to confidential material submitted by CCAs in any Commission proceeding."[7] The Joint Utilities raise similar concerns. [8]

In addition, the Joint Utilities seek clarification of the specific rules that will be applied to CCAs. They request that the Commission resolve the Petition by:

- Making clear that the Commission's confidentiality rules and processes apply equally to CCAs;
- Requiring CCAs to use the IOU matrix, not the ESP matrix as a basis for requests for confidential treatment and noting that CCA information not addressed in the applicable matrix is not presumed to be confidential; and
- Directing CCAs to submit future requests for confidential treatment on an individual basis supported by the required particularized showing.

CalCCA's petition aims not to withhold information from disclosure but simply to achieve the same protections for CCAs as other load-serving entities enjoy. As discussed below, CalCCA has concluded, and continues to maintain, that CCAs are more similarly situated to ESPs than IOUs for purposes of confidentiality under D.06-06-066 and thus the ESP matrix should apply.

Unlike IOUs and ESPs, however, CCAs operate under strict requirements for disclosure of information due to their status as governmental entities and the applicability of the PRA. Specifically, a party requesting information pursuant to the PRA could argue that information

---

6 Petition at Ex. 2-1.

7 TURN Response at 1.

8 Joint Utilities Response at 10.

CCAs share with parties in Commission proceedings, even pursuant to a non-disclosure agreement (NDA), waives otherwise applicable exemptions from disclosure. Consequently, additional clarifications are necessary.

Thus, CalCCA requests the Commission adopt a CCA matrix identical to the current ESP matrix. CalCCA also proposes CCAs not be subject to an obligation to make information available to intervenors or others designated by the Commission, as such disclosure potentially waives otherwise applicable exemptions under the PRA.

In response to comments, however, CalCCA offers an alternative. Absent a legislative solution modifying the PRA – the only way to address CCAs' exposure with certainty – the Commission could order CCAs to make information available to intervenors or others designated by the Commission under an NDA. To prevent a waiver under the PRA, the Commission must also conclude the following in its order, as conclusions of law: (1) information disclosed by CCAs pursuant to the Decision must be kept confidential pursuant to an NDA, and (2) disclosure pursuant to the Commission's order does not constitute a waiver of the exemptions otherwise available to such information under the Act.

II. THE ESP MATRIX CORRECTLY REFLECTS CCAS' DATA SUBMISSION REQUIREMENTS AND SHOULD BE APPLIED TO CCAS

In their Joint Response, the IOUs argue that the Commission should apply the IOU matrix to CCAs, as opposed to the ESP matrix. The Joint Utilities argue the IOU matrix is nonetheless appropriate for CCAs, noting that "[b]ecause the CCAs are likely to be required to submit procurement information that is covered by the IOU matrix – whether now or in the future – it make sense to direct CCAs to apply the IOU matrix, rather than the ESP matrix, which may not fully cover information provided by CCAs." However, the IOU matrix categories that differ from the ESP matrix concern items that largely are not relevant to CCAs, including electric price forecasts, forecasts of revenue requirements and customer rates, and categories of contracts that are simply inapplicable to CCAs (*e.g.,* contracts between utilities and their affiliates, and non-RPS contracts between utilities and non-affiliated third parties). While these data are relevant for rate-regulated utilities, the Commission does not regulate CCA rates, and these data are not relevant to the Resource Adequacy (RA), Renewable Portfolio Standard (RPS) or Integrated Resource Planning (IRP) submissions.

In contrast, the ESP matrix covers a more limited number of categories of information, which are more relevant to CCA submissions to the Commission. For example, the matrix includes contract data that will be submitted to the Commission pursuant to its jurisdiction over RA and RPS compliance. CalCCA respectfully submits that if in the future data submission requirements applicable to CCAs change to more closely resemble those of the IOUs, the matrix can be revisited. Until such time, CalCCA suggests the ESP matrix is appropriate for CCAs, as well.

CalCCA attaches hereto a revised matrix for application to CCAs that is identical to the current ESP matrix, replacing the proposed matrix attached to the Petition, which inadvertently copied language from an outdated version of the ESP matrix. Thus, CalCCA respectfully requests the attached Exhibit 1 be used in place of Exhibit 1 in the Petition.

III. THE COMMISSION SHOULD RECOGNIZE THE UNIQUE CIRCUMSTANCES CCAS FACE UNDER THE PUBLIC RECORDS ACT

The Joint Utilities and TURN seek to include CCAs within the scope of Ordering Paragraph (OP) 11 of the Decision. That paragraph provides:

> Generally, intervenor groups that are non-market participants and other parties that the Commission may so designate may have access to confidential IOU

> and/or ESP market sensitive information provided such parties shall comply with Commission directives for protecting the confidentiality of such information.[9]

The Joint Utilities and TURN argue that CalCCA's proposal to refer in this paragraph to CCAs' obligations under the PRA would create a dual process, whereby intervenors and other requesters would obtain information from the IOUs and ESPs via Commission directives, but be required to request information from CCAs under the Act. Therefore, they argue, including the language requested by the CCAs would provide preferential treatment to CCAs.

The Joint Utilities and TURN fail to recognize that CCAs and IOUs/ESPs are not similarly situated in providing information to intervenors. As governmental entities, CCAs are subject to the PRA, and all information disclosed is presumed to be public unless it falls within one or more of the Act's exemptions.[10] Critically, under Section 6254.5 of the Act, if an agency subject to the Act discloses a public record that is otherwise exempt "to a member of the public, this disclosure shall constitute a waiver of the exemptions specified . . . ."[11] Once waived, the information becomes subject to disclosure to the public pursuant to requests under the Act.

Certain disclosures are deemed by statute not to constitute such waivers. One such exemption applies to disclosures "made to a governmental agency that agrees to treat the disclosed material as confidential."[12] Thus, disclosures made by a CCA to the CPUC generally do not constitute "waivers" of the exemptions to disclosure applicable to such records. Additionally, an exemption to the Act's waiver provision applies to disclosures "made through other legal proceedings or as otherwise required by law."[13]

---

9 D.06-06-066, as modified by D.07-05-032.

10 CAL. GOV'T CODE §6253.

11 CAL. GOV'T CODE §6254.5.

12 CAL. GOV'T CODE §6254.5(e).

13 CAL. GOV'T CODE § 6254.5(b).

However, a party requesting information under the Act could argue that disclosures by CCAs under OP 11 to intervenors or others designated by the Commission would not fall under any exemption. Thus, unique to CCAs, disclosure of otherwise confidential information to an intervenor or other party to a Commission proceeding, even under an NDA, could deem such disclosure a waiver of otherwise available exemptions. The result would be inequitable treatment among CCAs and IOUs/ESPs: if a CCA provides information to TURN under an NDA, the information could be deemed publicly available; if an IOU or ESP provided the same information to TURN, it would not.

IV. THE COMMISSION SHOULD ORDER CCAS TO DISCLOSE INFORMATION TO PARTIES SUBJECT TO NON-DISCLOSURE AGREEMENTS OR COMMISSION ORDERS PROTECTING CONFIDENTIALITY, AND CONCLUDE THAT SUCH DISCLOSURE DOES NOT WAIVE OTHER EXEMPTIONS

CalCCA understands TURN's concerns and has considered alternatives to address them while preserving CCA confidentiality. CalCCA suggests alternative language that addresses both the Joint Utilities' and TURN's concerns, and CCAs' legal obligations. As noted above, the Act exempts disclosures "made through other legal proceedings or as otherwise required by law."[14]

A legislative fix to the Act would provide absolute certainty that CCA confidentiality would be secured. However, Commission action could provide significant comfort to CCAs and clarity to all interested parties. The Commission could include in the decision resolving this Petition a specific conclusion of law that disclosure under OP 11 does not constitute a waiver of otherwise applicable exemptions available under the Act. The Commission could then amend OP 11 to include a requirement that CCAs disclose information to intervenors and others

[14] CAL. GOV'T CODE §6254.5(b).

designated by the Commission in the same manner and subject to the same conditions as IOUs and ESPs. Although without legislative action there is no guarantee a reviewing court would agree, with these revisions CCAs could rely on the exemption to the waiver provision for disclosures "made through other legal proceedings or as otherwise required by law." This treatment would ensure equivalent treatment of IOUs, ESPs, and CCAs under the decision to the greatest extent achievable by the Commission.

To achieve this result, CalCCA proposes OP 11 be amended to make the CCAs' obligation explicit:

> Generally, intervenor groups that are non-market participants and other parties that the Commission may so designate may have access to confidential IOU, CCA, and/or ESP market sensitive information provided such parties shall comply with Commission directives for protecting the confidentiality of such information. CCAs are required to make confidential market sensitive information available to non-market participants and other parties that the Commission may so designate provided such parties comply with non-disclosure agreements or specific Commission orders protecting the confidentiality of such information.

CalCCA also proposes a new Conclusion of Law be added to the Decision, as follows:

> Conclusion of Law 25
>
> Disclosure by CCAs of confidential market sensitive information to intervenors or others designated by the Commission pursuant to this Decision and subject to a non-disclosure agreement or specific Commission order protecting the confidentiality of such information shall be deemed exempt from public disclosure pursuant to Government Code §6254.5(b) and thus shall not constitute a waiver of exemptions otherwise available to the information under the California Public Records Act.

V. CONCLUSION

For the aforementioned reasons, on behalf of its members CalCCA respectfully requests the Commission modify D.06-06-066 as amended by D.07-05-032, D.06-12-030, and D.08-04-

023, to clarify how its provisions interact with the PRA, and to adopt the attached form of "CCA Matrix."

Respectfully submitted,

/s/ Ann Springgate

Counsel to the
California Community Choice Association

March 9, 2020

EXHIBIT 1
Appendix 2A to D.06-06-066-CCA Matrix

Order Instituting Rulemaking (OIR) 05-06-040[1] Matrix of Allowed Confidential Treatment Community Choice Aggregator (CCA) Data		
Item	**Public/Confidential Treatment**	**Explanation of Item**
I) Renewables Portfolio Standard (RPS) Information		
A) RPS compliance filings required by CPUC, by CCA	Public, unless disclosure of first three years of forecast retail sales and resource mix data (MWh) and/or historical retail sales and supply data (MWh) for prior year would reveal entire net short of CCA.	Includes one-time and recurring reporting. Shows current and projected contents of a CCA's RPS portfolios, including sales and resource mix.
B) Annual RPS compliance filings, by CCA	Public, unless disclosure of first three years of forecast retail sales and resource mix data (MWh) or of historical retail sales and supply data would reveal the entire net short of CCA.	Includes Annual Procurement Target (APT) reporting required in Rulemaking 04-04-026 and all other required reports.
C) RPS contracts	Contract summaries public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date.	

[1] A CCA need not seek confidential treatment every time it makes a compliance filing of a repetitive nature. Instead, on making subsequent compliance filings, the CCA may cite the earlier motion for confidentiality and ruling on said motion.

EXHIBIT 1
Appendix 2A to D.06-06-066-CCA Matrix

Order Instituting Rulemaking (OIR) 05-06-040[1] Matrix of Allowed Confidential Treatment Community Choice Aggregator (CCA) Data		
Item	**Public/Confidential Treatment**	**Explanation of Item**
	Other terms confidential for three years[2], or until one year following expiration, whichever comes first.	
II) Resource Adequacy Information		
A) Detailed load forecasts (both year ahead and month ahead)	Front three years of forecast data confidential.	Year ahead data show that CCA has secured adequate generation capacity to cover 90% of its forecast peak load for next year's summer months. Month ahead data show that CCA has secured adequate capacity to cover 100% of its forecast load plus a reserve requirement.
B) Supply data (both year ahead and month ahead)	Supply data for first 3 years of forecast period confidential.	Year ahead data show that CCA has secured adequate generation capacity to cover 90% of its forecast peak load for next year's summer months or 100% of its annual local RA requirements. Month ahead data show that CCA has secured adequate capacity to cover 100% of its forecast load plus a reserve requirement.
C) Recorded hourly loads and monthly peak loads	Public after one year.	Recorded load data provided by CCAs for RA compliance.

2 Where this Matrix allows confidential treatment for a period of time, that period shall begin on the first date a CCA submits the data to the Commission.

Order Instituting Rulemaking (OIR) 05-06-040[1] Matrix of Allowed Confidential Treatment Community Choice Aggregator (CCA) Data		
Item	**Public/Confidential Treatment**	**Explanation of Item**
D) Customer counts by month	Public.	Monthly customer count data used to evaluate reliability of CCA load forecasts.
III) Load Forecast Information and Data – Electric		
A) Load Serving Entity (LSE) demand forecasting methodology	Public.	General descriptive information regarding the methodology used by LSEs when estimating future expected electric capacity and energy needs.
B) LSE Total Peak Load Forecast - (MW)	Front three years of forecast data confidential.	Each LSE's own forecast of its bundled customer peak load. CCAs file annual and monthly data in CEC IEPR Forms 1.3 (annual sectoral peak demand forecasts) and 1 (monthly peak demand for total CCA peak load).
C) LSE Total Energy Forecast – (MWh)	Front three years of forecast data confidential.	CCAs file annual and monthly data in CEC IEPR Forms 1.3 (annual sectoral energy forecasts) and 2 (monthly energy forecast on a total CCA load basis).
D) Total Peak Demand Load Forecast - IOU Planning Area (MW)	Annual and Quarterly data: Public. Monthly and Daily data: Front three years of forecast data confidential	CCAs file annual and monthly data in CEC IEPR Forms 1.3 (annual forecasts) and 2 (monthly forecasts). When CCA data aggregated with that of other LSEs, can create planning area forecast.
E) Detailed load forecasts filed in spring for upcoming year, by CCA	Upcoming year forecast confidential; public once data is one year old.	
IV) Bilateral Contract Terms and Conditions – Electric		

Order Instituting Rulemaking (OIR) 05-06-040[1] Matrix of Allowed Confidential Treatment Community Choice Aggregator (CCA) Data		
Item	**Public/Confidential Treatment**	**Explanation of Item**
A) Contracts and power purchase agreements between CCAs and IOUs (except RPS)	Contract summaries public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date. Other terms confidential for three years from date contract states deliveries to begin; or until one year following expiration, whichever comes first.	Specific contracts between the IOU and CCA to deliver power to IOUs. The contract information includes the capacity, energy, timing, and pricing terms of the contracts.
B) Expired Power Purchase Agreements (PPAs)	Contract summaries public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date. Other terms confidential for three years from date contract states deliveries to begin; or until one year following expiration, whichever comes first.	Terminated CCA-IOU Power Purchase Agreements under which power is no longer delivered.
C) Bilateral contracts	Contract summaries public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date.	Includes contracts of greater and fewer than 5 years in duration.

Order Instituting Rulemaking (OIR) 05-06-040[1] Matrix of Allowed Confidential Treatment Community Choice Aggregator (CCA) Data		
Item	**Public/Confidential Treatment**	**Explanation of Item**
	Other terms confidential for three years from date contract states deliveries to begin; or until one year following expiration, whichever comes first.	
V.) Recorded (Historical) Data and Information - Electric		
D) Market purchases of energy and capacity	Public after data are one year old.	

EXHIBIT 2
Proposed Modifications to D.06-06-066 as amended

D.06-06-066
Conclusions of Law

15. The confidentiality rules applicable to IOUs, ~~and~~ ESPs and CCAs need not be identical.

22. It is reasonable to adopt the IOU Matrix, ~~and~~ ESP Matrix, and CCA Matrix. We balance the need for open decision making and meaningful public participation with the legitimate needs of parties that come before us for confidential treatment of their data as allowed by law.

23. There may be differences between parties that justify different *substantive* treatment of data. No type of entity (*e.g.*, IOU, ~~or~~ ESP, or CCA) shall receive greater confidentiality for its data merely because it is such an entity.

25. Disclosure by CCAs of confidential market sensitive information to intervenors or others designated by the Commission pursuant to this Decision and subject to a non-disclosure agreement or specific Commission order protecting the confidentiality of such information shall be deemed exempt from public disclosure pursuant to Government Code §6254.5(b) and thus shall not constitute a waiver of exemptions otherwise available to the information under the California Public Records Act.

Ordering Paragraphs

1. Where we find that data are market sensitive pursuant to Pub. Util. Code §454.5(g) or otherwise entitled to confidentiality protection, in most cases, we adopt a window of confidentiality for Investor-Owned Utility (IOU), Community Choice Aggregator (CCA), and Energy Service Provider (ESP) data that protects it for three years into the future, and one year in the past.

2. We adopt the confidentiality conclusions set forth in the IOU Matrix, ~~and~~ ESP Matrix and CCA Matrix attached hereto as Appendices 1, 2, and 2A (collectively Matrix, unless otherwise stated). Where a party seeks confidentiality protection for data contained in the Matrix, its burden shall be to prove that the data match the Matrix category. Once it does so, it is entitled to the protection the Matrix provides for that category. The submitting party must file a motion in accordance with Law and Motion Resolution ALJ-164 or any successor Rule, accompanied with any proposed designation of confidentiality, proving:

1.) That the material it is submitting constitutes a particular type of data listed in the Matrix,

2.) Which category or categories in the Matrix the data correspond to,

3.) That it is complying with the limitations on confidentiality specified in the Matrix for that type of data,

4.) That the information is not already public, and

5.) That the data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure.

11. Generally, intervenor groups that are non-market participants and other parties that the Commission may so designate may have access to confidential IOU, CCA, and/or ESP market sensitive information provided such parties shall comply with Commission directives for protecting the confidentiality of such information. CCAs are required to make confidential market sensitive information available to non-market participants and other parties that the Commission may so designate provided such parties comply with non-

disclosure agreements or specific Commission orders protecting the confidentiality of such information.

13. With this decision, we commence Phase Two of this proceeding. Respondents shall, and other parties may, file and serve comment on whether it is appropriate for us to develop the following requirements within 30 days of Commission adoption of this decision:

1.) A motion that simply asserts, without explanation, that the data contain trade secrets or "market sensitive" information will denied as incomplete.

2.) A party whose motion has been denied for violation of item 1 that refiles the motion in substantively the same form may be subject to penalties pursuant to §2107 at the discretion of the Assigned Commissioner, Assigned Administrative Law Judge (ALJ) or Law and Motion ALJ.

3.) A party seeking confidentiality treatment shall provide in its motion, in text or table form, the following information:

   a. Legal basis for asserting confidentiality (*e.g.*, §454.5(g), trade secret, privilege);

   b. If covered by the IOU, ~~or~~ ESP, or CCA Matrix in R.05-06-040, the category/ies into which the data fall, with an explanation of how the data match the category/ies in the Matrix.;

   c. Discussion of why the data should be kept under seal;

   d. Identification of appropriate procedures short of submitting entire documents under seal or in redacted form, such as partial sealing of documents; partial redaction; aggregation of data to mask individualized, sensitive information; delayed information release (after documents are no longer market sensitive); restriction on personnel with access to documents; use of averages, percentages or annualization of data instead of monthly or hourly data; and issuance of guidelines for parties to follow in producing redacted information (*e.g.*, leaving headings in documents; limiting redactions to figures only; and leaving sufficient information in documents to give other parties notice of what has been redacted).

4.) Parties may not assume that their motions have been granted if the Assigned Commissioner, Assigned ALJ or Law and Motion ALJ do not act on them. The onus shall be on parties to follow up with the Assigned Commissioner, ALJ or Law and Motion ALJ to seek a ruling, if one is not issued within 60 days of filing of the motion.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Consider the Ratemaking and Other Implications of a Proposed Plan for Resolution of Voluntary Cases filed by Pacific Gas and Electric Company Pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088.	Investigation 19-09-016 (Filed September 26, 2019)

OPENING BRIEF AND COMMENTS OF
MARIN CLEAN ENERGY

Elizabeth M. Kelly
LAW OFFICE OF ELIZABETH KELLY
P.O. Box 225037
San Francisco, CA 94122
Telephone: (415) 535-9998
Email: beth@emk-law.com

Counsel for:
MARIN CLEAN ENERGY

Michael Callahan
Senior Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6045
Email: mcallahan@mcecleanenergy.org

March 13, 2019

TABLE OF CONTENTS

TABLE OF AUTHORITIES

<u>CASES</u>

<u>STATUTES</u>

<u>COMMISSION DECISIONS</u>

RULES

EXHIBITS

HEARING TRANSCRIPTS

BANKRUPTCY COURT FILINGS

SUMMARY OF RECOMMENDATIONS

In this brief and comments, MCE does not recommend rejecting the PG&E Plan; rather, MCE provides proposals to protect ratepayers and the public interest, including:

(1) Revisions to the PG&E Plan;

(2) Conditions of approval to the revised PG&E Plan; and

(3) Enforcement and protection procedures post-bankruptcy to ensure PG&E's promises become fulfilled commitments.

BRIEF RECOMMENDATIONS

The Current Proceeding (Enforcement and Protection)

MCE recommends that this proceeding remain open to be the venue for:

- Enforcing "neutral, on average" and "contributions of ratepayers"; and
- Ensuring compliance with additional elements of the PG&E plan as well as the Assigned Commissioner's Proposals, such as Enhanced Oversight and Enforcement.

Structural Proposals, Including Wires Only

MCE recommends that the Commission:

- Ensure that structural changes to PG&E remain available to the Commission post-bankruptcy; and
- Take steps to transition PG&E out of the retail electric generation service to simplify operations and improve their focus on safety.

"Neutral, On Average" and "Contributions of Ratepayers"

In order to achieve and maintain cost neutrality and recognize the contributions of ratepayers, MCE recommends that the Commission:

- Define the "ground" rules for cost recovery from ratepayers including:
    - Prohibiting on an upfront basis certain costs ineligible for ratepayer recovery, including PG&E's bankruptcy costs;
    - Disallowing rate recovery of any amounts determined to be ratepayer contributions;
    - Holding PG&E accountable to its clarifications to not recover, at minimum: (1) financing costs associated with Wildfire Fund contributions; (2) bankruptcy-related professional fees; (3) equity backstop fees; (4) holding company bridge

fees; and (5) 2017 and 2018 wildfire claims costs if the Commission decides to approve the $7 billion securitization proposal;

- Providing that following each determination of a "ratepayer contribution" in this proceeding, PG&E should have a 30-day window to file a motion in this proceeding containing a disallowance schedule for tracking and ensuring "neutral, on average" and "contributions of ratepayers" continue to be met; and
- Ensuring that any amounts required to be contributed to the Fire Victim Trust by PG&E should not be recoverable in rates.

Receivership

MCE recommends that PG&E consent to, and the Commission seek, appointment of a receiver to PG&E. PG&E has demonstrated that:

- there is a grave and immediate threat or actuality of harm;
- the use of less extreme measures of remediation have been exhausted and proven futile;
- continued insistence that compliance with the Court's orders would lead only to confrontation and delay;
- there is a lack of leadership to turn the tide within a reasonable period of time;
- there is bad faith;
- resources are being wasted; and
- a receiver is likely to provide a relatively quick and efficient remedy.

Revocation of the Holding Company Authorization

MCE Recommends that the Commission:

- Immediately order a directed outcome to prohibit PG&E – including PG&E Corporation – from entering into transactions that decapitalize PG&E for the benefit of PG&E's shareholders until such time as: (1) PG&E is in compliance with all financing and holding company requirements, or (2) the Commission has revoked PG&E's holding company authorization and deemed such transactions reasonable.
- Reject PG&E's aggressive requests for waivers from existing rules, including:
  - PG&E's violation of the first priority condition;
  - PG&E's request for waiver – including permanent waiver – from the Commission's capital structure requirements; and
  - PG&E's request for increase to its short-term debt authorization.
- Revoke PG&E's holding company authorization.

The PG&E Plan and PG&E's Governance "in Light of" AB 1054 Standards

MCE Recommends that the Commission:

- Find that the PG&E Plan and PG&E's governance structure, as proposed, fails to meet the standard of AB 1054 "in light of" PG&E's safety history and criminal probation; and
- Find that the PG&E Plan and PG&E's governance structure, as proposed, fail to meet the standard of AB 1054 "in light of" PG&E's recent financial condition.

Financing Authorizations

Generally

The Commission must:

- Deny any transaction that violates Section 701.5 which prohibits a utility from providing a guaranty to its holding company;
- Deny or require expedited cure for any failure to comply with Rule 3.5 which provides the Commission with necessary information to make a determination on any debt proposed; and
- Reject all improper uses of financing funds, including any funds transfers from the Utility to the Corporation or to shareholders in violation of the "first priority condition."

$11.85 Billion in Long Term Noteholder RSA Debt ("New Noteholder RSA Debt")

MCE Recommends:

- The Commission should deny the conversation of unsecured to secured debt by PG&E under the Noteholder RSA without any benefit to ratepayers; and
- If the Commission approves the transaction, the Commission should find that the "contributions of ratepayers" includes the differential in interest rates between secured and unsecured debt.

Up to $11.925 billion Total in Additional Short-Term Debt and/or Long-Term Debt ("New Additional Utility Debt")

MCE Recommends:

- To the extent the Commission authorizes the Additional Short-Term Debt or the New Additional Utility Debt, the Commission should authorize no more than $11.925 billion total under these two borrowing segments;
- The Commission should require additional disclosures regarding the refinancing of Pollution Control Bonds, including the counterparties of the proposed transaction and any and all associated claims, including, but not limited to, Pollution Control Bond (2008 F and 2010 E) and the value of those associated claims;
- The Commission should reject the Temporary Utility Debt as it proposes a guaranty of Utility assets for the benefit of the holding company in violation of Section 701.5; and

- The Long-Term Debt authorization request must be denied as it fails to contain any terms and conditions, term sheets or other information necessary for the Commission to make a determination, in violation of Rule 3.5.

Up to An Additional $6 Billion in Short-Term Debt

The Commission must deny PG&E's request for "up to an additional $6 billion in short-term debt as it has no terms and conditions, term sheets or information necessary for the Commission to make a determination in violation of Rule 3.5.

Securitization Proposal

The Commission should ensure that any securitization proposal exclude Community Choice Aggregator (CCA) revenues and other excluded revenues consistent with the Final Order regarding Customer Programs, including Pubic Purpose Programs.[1] These Customer Programs are defined in the associated Motion of the Debtors, and include (i) Deposit and Reimbursement Programs, (ii) Public Purpose Programs, (iii) Environmental Cleanup Programs, (iv) Third-Party Programs, which includes CCA, (v) GHG Credit Programs, and (vi) Customer Support Programs. The Commission should issue an order to ensure PG&E will not pledge these revenues as security for debt.

Fines and Penalties

The Commission should order PG&E to pay fines and penalties: (1) in full, and (2) without reducing Fire Victims Trust amounts.

ASSIGNED COMMISSIONER PROPOSAL RECOMMENDATIONS

Proposal #4 Board of Directors

MCE recommends that:

- Directors not be shared extensively between the Corporation and the Company; and
- All Directors should be required to be residents in PG&E service territory during their tenure.

Proposal #6 Regional Restructuring

MCE recommends:

- The Commission ensure that the PG&E Plan and the Regional Restructuring not preclude or preempt any other Commission-led restructuring of PG&E, including the process to make PG&E a wires-only company for electricity service; and

[1] [Dkt. 843].

- The Commission explore splitting PG&E into affiliates along functional and geographic lines.

Proposal #7 Safety and Operational Metrics

MCE recommends that:

- PG&E's safety and operational metrics include performance-based metrics to measure progress toward safety, affordability, reliability, equity, and climate outcomes to strengthen the shareholder interest in achieving those outcomes; and
- PG&E be precluded from defining the appropriate metrics, rather this should be performed in the fully transparent environment of the Commission.

Proposal #9 Executive Compensation

MCE recommends that:

- PG&E's executive compensation metrics be developed under the oversight of the Commission;
- The Commission ensure compensation arrangements are public;
- The focus on "financial performance" in PG&E's metrics must instead be "financial health";
- 95% of incentive payments should be tied to safety outcomes;
- Incentive payments should be prohibited if PG&E causes a safety incident that results in any fatalities; and
- Incentive compensation for all employees, including the CEO, be comprised of short-term and long-term incentives. Such incentives must be based upon the financial health and operatorial outcomes (including safety) of the utility, not shareholder-focused metrics such as earnings per share.

Proposal #10 Enhanced Oversight and Enforcement

MCE recommends that the Commission:

- Expand the focus of this enforcement beyond safety to include root causes;
- Create a "Step 0" of permanent enhanced oversight to improve transparency, which would include the formation of an Oversight Committee and increased transparency requirements;
- Augment "Step 4" (Chief Restructuring Officer) to also include a Commission-appointed examiner;
- Modify "Step 5" to reflect the involvement of the Federal Courts and to ensure that a receiver is broadly empowered to consider all options, including, for example, the sale of the gas business; and
- Ensure the availability of "Step 6" (Revocation of the CPCN) in the event of necessity or if other remedial steps are unfruitful.

MCE further recommends that the Commission take steps to place PG&E into "Step 5": Receivership.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Consider the Ratemaking and Other Implications of a Proposed Plan for Resolution of Voluntary Cases filed by Pacific Gas and Electric Company Pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088.	Investigation 19-09-016 (Filed September 26, 2019)

OPENING BRIEF AND COMMENTS OF
MARIN CLEAN ENERGY

Marin Clean Energy ("MCE") respectfully submits the following Opening Brief and Opening Comments pursuant to: (1) Rule 13.11 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure;[2] (2) the November 14, 2019 Assigned Commissioner's Scoping Memo and Ruling; (3) the November 27, 2019 ALJ Ruling on Public Utilities Code Section 854;[3] the February 18, 2020 Assigned Commissioner's Ruling and Proposals ("ACR"); and (5) the March 6, 2020 ALJ Ruling Confirming Modification of Procedural Schedule.

[2] "Rule" as set forth herein means the Commission Rules of Practice and Procedure unless otherwise indicated.

[3] All "Section" references set forth herein are to the P.U. Code unless otherwise indicated.

CHAPTER 1. INTRODUCTION

In this proceeding, Pacific Gas and Electric Company (the "Company" or the "Utility") seeks to resolve its voluntary case of reorganization filed by the company and its holding company, Pacific Gas and Electric Corporation (the "Corporation" or "HoldCo", together with the Utility, "PG&E") pursuant to Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court, Northern District of California, San Francisco Division ("Bankruptcy Court"), *In re* Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088 ("Bankruptcy Case").[4]

On January 31, 2020, PG&E filed its amended plan of reorganization ("Plan of Reorganization") with the Bankruptcy Court.[5] On that same day, PG&E filed its Prepared Testimony in this proceeding setting forth PG&E's plan to emerge from bankruptcy ("PG&E Plan").[6] The PG&E Plan is broader than the Plan of Reorganization.

MCE on March 9, 2020, PG&E filed a further amended plan of reorganization.[7] The primary purpose of such amendment was to further strengthen the position of shareholders, as set forth on Appendix A.

---

[4] In this filing, MCE refers to documents filed by PG&E in the Bankruptcy Case and seeks judicial notice thereof. Each such filing is indicated by a standard bankruptcy reference to a docket number, namely: [Dkt. ####]. Each document may be publicly accessed by going to the bankruptcy docket at https://restructuring.primeclerk.com/pge/Home-DocketInfo. The docket number can be entered into the search bar.

[5] [Dkt. 5590] *Amended Chapter 11 Plan Debtors' and Shareholder Proponents' Joint Chapter 11 Plan of Reorganization Dated January 31, 2020 Filed by Debtor PG&E Corporation*.

[6] Exhibit PG&E-1 and supporting volumes.

[7] [Dkt. 6218] PG&E Plan of Reorganization dated March 9, 2020 (Redline). MCE refers in this brief and comments to the Plan of Reorganization dated January 31, 2020. References in this subsection are to paragraph numbers of [Dkt. 6218].

In this brief and comments, MCE does not recommend rejecting the PG&E Plan; rather, MCE provides proposed:

(1) Revisions to the PG&E Plan;
(2) Conditions of approval to the revised PG&E Plan; and
(3) Enforcement and protection procedures post-bankruptcy to ensure PG&E's promises become fulfilled commitments.

PG&E's primary interest in their bankruptcy has been to protect its shareholders, rather than planning for a better future or mitigating the substantial risk PG&E poses to ratepayers and the public. The Commission has the opportunity – and obligation – to protect the public interest.

PG&E entered bankruptcy after causing several devastating fires and incurring tens of billions of dollars in associated liabilities. In order to maximize their payout from the bankruptcy case, PG&E's unsecured bondholders initiated what some have called a hostile takeover. This was accomplished, in part, by introducing a competing restructuring plan that would fully and immediately compensate fire victims and largely wipe out PG&E's existing shareholders. This plan drew the support of the fire victims represented by the Torts Claimants Committee and represented a serious threat to PG&E's existing shareholders.

Subsequently, PG&E worked to neutralize the threat and protect its shareholders. This was accomplished by both agreeing to compensate fire victims at an equal dollar amount to the competing plan and by awarding the unsecured bondholders up-front fees and a security interest in PG&E's assets.[8] This maneuvering neutralized the competing plan and stopped the threat to existing shareholders. However, the PG&E Plan does not pay fire victims immediately. It provides half of their compensation in depressed shares of stock in PG&E's holding company that must

[8] Exhibit Abrams-1, Testimony at p. 6-7.

recover in value for fire victims to be made whole. Regarding whether the treatment of fire victims has been fair, PG&E's CEO stated:

"You know, fairness is often in the eye of the beholder."[9]

PG&E's decision to provide a security interest in nearly all of its assets exposes ratepayers to significant financial risk (including over-leveraging, undercapitalizing, and the real risk of PG&E returning to bankruptcy yet again), and dramatically limits PG&E's ability to finance and pay for future liabilities or investments.[10] PG&E has protected its shareholders while giving ratepayers and fire victims second-class treatment.

The Legislature responded to credit rating agencies' and PG&E's requests passing Senate Bill ("SB") 901 (2018) and Assembly Bill ("AB") 1054 (2019) to create financial safety valves for PG&E shareholders. In response to providing PG&E a significant financial cushion, funded by the public and ratepayers, PG&E chose to protect its own shareholders and max out its ability to borrow through its plan.

MCE recognizes that the PG&E Plan of Reorganization is the only plan currently pending before the Bankruptcy Court that would give PG&E a path to exit bankruptcy. Further, MCE recognizes that PG&E has decided that it must access the AB 1054 Wildfire Fund in order to remain a viable entity. PG&E has only offered this "Plan A" and has rejected all opportunities to consider a "Plan B" that would better serve the public interest. The Commission must not overlook the significant issues and deficiencies presented by the PG&E Plan. Rather, the Commission needs to take proactive steps both now and after PG&E's emergence from bankruptcy to meet the needs of ratepayers and the public.

---

[9] Johnson (PG&E), Hearing Transcript Vol.1 (February 25, 2020), at 102 line 25 to 27.

[10] *See* Section VII.B.

CHAPTER 2. OPENING BRIEF

I. THE COMMISSION SHOULD INITIATE A PROCESS TO MAKE PG&E A WIRES-ONLY COMPANY

Within the Plan of Reorganization, PG&E requires "CPUC Approval" including "(b) a disposition of proposals for certain potential changes to the Utility's corporate structure and authorizations to operate as a utility."[11] The Commission should reject this requested moratorium on structural changes to PG&E. MCE recommends that Safety Order Instituting Investigation[12] remain open to consider necessary and appropriate changes to the Utility's corporate structure and authorizations to operate as a utility such as making PG&E a wires-only company for electricity service. MCE supports the testimony and proposals set forth by the Joint CCAs.[13]

PG&E should be transitioned out of the retail electric generation service to simplify operations and improve their focus on safety. PG&E is one of the largest utilities in the country and is entrusted to serve 16 million people across California.[14] However, PG&E's size and complexity of operations has been a barrier to safety.[15] Over the last ten years, PG&E has caused nearly 100 deaths in a series of safety catastrophes starting with the San Bruno pipeline explosion and continuing through the Camp Fire. As a result of San Bruno, PG&E was convicted of a felony, yet subsequently falsified safety-related records related to their "locate and mark" program for

---

[11] Plan of Reorganization, Section 1.37.

[12] Investigation (I.) 15-08-019.

[13] Exhibit Joint CCA-1 (Beach).

[14] Exhibit Joint CCA-1 (Beach), at p. 9 lines 12-15.

[15] Exhibit Joint CCA-1 (Beach), at p. 9 line 8 to p. 11 line 1.

underground lines.[16] Neither Judge Alsup, who is overseeing PG&E's felony probation, nor the Commission, through fines[17] and the Safety Culture Investigation, have been able to avert continued catastrophes.

Throughout this brief, MCE identifies concerns with the PG&E Plan as being contrary to the public interest and focused on the short-term interest of existing shareholders. Simply put, the plan is inadequate and does not represent the change California deserves after PG&E-caused disasters. The Commission should send a clear and powerful signal to PG&E to renew its focus on safety by initiating a process to remove PG&E from the retail electric generation service.

The Commission should initiate the process through the Safety Culture Investigation to explore how to accomplish the transition and over what period of time. Making PG&E a wires-only company will be a significant change with a limited financial impact to PG&E because their retail generation service is essentially a passthrough. PG&E makes the vast majority of its profit from capital invested in physical assets (*i.e.* the "rate base") which would be largely unaffected by such a shift.

As set forth in the Joint CCA Testimony, these benefits include: a reduction of debt equivalence on the books of the Utility and improved focus on more critical lines of business which have had a history of challenges with regard to safety.[18]

Transitioning PG&E out of the retail electric generation service will save ratepayers money and should improve PG&E's safety performance.[19] It will also require careful examination of a number of issues such as the preservation and continued management of existing energy contracts.

---

[16] D._______ (decision number to be assigned) in I.19-06-015, dated February 27, 2020.

[17] E.g. D.15-04-025 (San Bruno pipeline explosion fines and remedies).

[18] Exhibit Joint CCA-1 (Beach), at ii.

[19] Exhibit Joint CCA-1 (Beach), at p. 11 line 1 to p. 12 line 17.

The Commission should direct this process to begin in this proceeding to send a signal to PG&E and its creditors to plan accordingly.

II. THE COMMISSION SHOULD HOLD PG&E TO ITS CLAIM OF RATE NEUTRALITY BY KEEPING THIS PROCEEDING OPEN AND ENFORCING FURTHER ACCOUNTABILITY

In order for PG&E to be eligible to participate in the Wildfire Fund, AB 1054 requires that the Commission determine that the reorganization plan and other documents resolving the insolvency proceeding are "neutral, on average, to the ratepayers of the electrical corporation"[20] and "recognize the contributions of ratepayers, if any, and compensate them accordingly through mechanisms approved by the commission, which may include sharing of value appreciation."[21] PG&E has claimed their plan is neutral on average to customers as required by AB 1054.[22] However, the full costs of the PG&E Plan are not known to the Commission at this time.[23] For example, PG&E is planning to file an application for its Regional Restructuring plan separately from this proceeding.[24] As a result, the Commission can only estimate ratepayer impacts at this time and should keep this proceeding open if it approves the PG&E Plan to ensure it is neutral to ratepayers.

In order to achieve and maintain cost neutrality and recognize the contributions of ratepayers, MCE recommends that the Commission:

- Keep this proceeding open as the venue for enforcing "neutral, on average" and "contributions of ratepayers";

---

[20] Public Utilities Code Sections 3291((b)(1)(D)(ii) and 3292(b)(1)(D)(ii).

[21] Public Utilities Code Sections 3291((b)(1)(E) and 3292((b)(1)(E).

[22] Exhibit PG&E-1 (Kenney) at 10-1.

[23] *See* Sections IV, VI, VII, and VIII of this brief.

[24] Exhibit PG&E-1 (Vesey) at 5-36.

- Define the "ground" rules for cost recovery from ratepayers including:
  - Prohibiting on an upfront basis certain costs ineligible for ratepayer recovery, including PG&E's bankruptcy costs;
  - Holding PG&E accountable to its clarifications to not recover, at minimum: (1) financing costs associated with Wildfire Fund contributions; (2) bankruptcy-related professional fees; (3) equity backstop fees; (4) holding company bridge fees; and (5) 2017 and 2018 wildfire claims costs if the Commission decides to approve the $7 billion securitization proposal.
  - Proving that following each determination of a "ratepayer contribution" in this proceeding, PG&E should have a 30-day window to file a motion in this proceeding containing a disallowance schedule for tracking and ensuring "neutral, on average" and "contributions of ratepayers" continue to be met.

MCE further recommends that this proceeding remain open to be the venue to ensure compliance with additional elements of the PG&E plan as well as the Assigned Commissioner's Proposals, such as Enhanced Oversight and Enforcement.

A. In Order to Achieve and Maintain Cost Neutrality, the Commission Should Set Ground Rules Defining Unrecoverable Costs Up Front and Establishing a Process for Further Accountability

1. Unrecoverable Costs

When the Commission makes a decision in this proceeding, MCE recommends that the Commission also set the "ground rules" for ratepayer recovery. Certain PG&E costs should be deemed, on an upfront basis, ineligible for ratepayer recovery. For example, for the last PG&E bankruptcy, "PG&E [was] not authorized to reimburse PG&E Corporation or any other unit of PG&E for professional fees and expenses in connection with the Chapter 11 case, nor [was] PG&E

authorized to charge ratepayers directly or indirectly for these costs."[25] PG&E also "reimburse[d] the Commission for its professional fees and expenses in the Chapter 11 case."[26]

Furthermore, *any amounts required to be contributed to the Fire Victim Trust by PG&E should not be recoverable in rates*.[27] These amounts result from fires caused by PG&E equipment and such costs are the responsibility of PG&E's shareholders.

The Commission should also issue orders to hold PG&E accountable to the clarifications it made about what costs it will not seek to recover.[28] These include: (1) financing costs associated with Wildfire Fund contributions; (2) bankruptcy-related professional fees; (3) equity backstop fees; (4) holding company bridge fees; and (5) 2017 and 2018 wildfire claims costs if the Commission decides to approve the $7 billion securitization proposal. The Commission should rely on PG&E's statements and order that these amounts are not recoverable from ratepayers.

2. Accounting for Contributions of Ratepayers

The PG&E Plan creates multiple types of costs that may be imposed on ratepayers. PG&E relies on various agreements and amendments ("transactions") developed through the bankruptcy process and incorporated or referenced in the PG&E Plan. There are also cumulative impacts resulting from multiple transactions or overarching structural elements that create ratepayer costs that cannot be easily tied to a single transaction ("broader impacts"). If the Commission approves the PG&E Plan, this proceeding should remain open to evaluate and determine for each transaction

---

[25] D.03-12-035 at 77.

[26] D.03-12-035 at 18.

[27] See Plan of Reorganization, Section 1.79.

[28] PG&E's Clarifications in Response to February 21, 2020 Testimony of Other Parties, served February 26, 2020 to the service list in this proceeding.

or broader impact (1) whether it would result in a ratepayer contribution; and (2) a quantified dollar figure for that contribution. Some examples of these transactions and broader impacts include:

- the $6 billion in ratepayer spend[29] PG&E triggered through its decision to include the AB 1054 Wildfire Fund in its restructuring plan;[30]
- the $6 billion in short-term temporary debt to pay pre-petition debt of the Corporation;[31]
- the $7 billion securitization of ratepayer revenues to pay for shareholder liabilities;[32]
- the $1.2 billion in equity backstop commitments including the payments to existing equity for these commitments ranging from a minimum of $764 million to an estimated $1.8 billion if PG&E is not able to get financing from other sources;[33]
- $2 billion in Debtor in Possession Financing for PG&E to continue operating during their bankruptcy;[34]
- renegotiated agreements with existing unsecured bondholders and the difference in fees;[35]
- the risk that PG&E has shifted to ratepayers through over-leveraging its finances is a broad impact that must be quantified, represents a valuable credit enhancement,

[29] D.19-10-056 at pp. 20, 31-32.

[30] Exhibit PG&E-1 (Johnson), at 1-7, lines 2-6.

[31] Exhibit PG&E-1 (Wells) at 2-10 lines 4-11.

[32] [Dkt. 6013].

[33] *Infra.* Section (Governance).C.5.

[34] Exhibit PG&E-1 (Wells) at 2-16.

[35] Exhibit PG&E-1 (Wells), Noteholder RSA Debt.

and may lead to significant ratepayer costs if PG&E incurs another large liability and is unable to pay;

- the costs associated with PG&E's Regional Restructuring proposal; and
- the bankruptcy and legal costs for PG&E and the state.

The Commission should disallow rate recovery of any amounts determined to be ratepayer contributions.[36] Such an approach may be financially infeasible for PG&E immediately upon its exit from bankruptcy due to being overleveraged through the PG&E Plan. While PG&E's financially precarious position upon exit is inappropriate and a significant risk to ratepayers, it may need to be accommodated through this proposal to give PG&E time to absorb the disallowance. To that end, following each determination of a ratepayer contribution in this proceeding, PG&E should have a 30-day window to file a motion in this proceeding containing a disallowance schedule that provides a timeline to ensure ratepayer neutrality. This proposal is a necessary condition for the Commission to find the PG&E Plan rate neutral and meet the requirements to access the AB 1054 Wildfire Fund.

B. This Proceeding Should Be the Venue to Ensure Compliance with Other Areas of the PG&E Plan and to Implement the Assigned Commissioner's Proposals

This proceeding should also remain open to ensure compliance with additional elements of the PG&E plan as well as the Assigned Commissioner's Proposals, such as Enhanced Oversight and Enforcement.

[36] Sections 3291(b)(1)(E) and 3292(b)(1)(E).

III. PG&E'S GOVERANCE IS INADEQUATE AND EVEN IF SIGNIFICANT CHANGES IN GOVERNANCE OCCUR, PG&E IS ELEGIBLE FOR RECEIVERSHIP

While the Commission's determinations regarding the PG&E Plan are essential to this proceeding, MCE asks that the Commission not lose sight of the bigger picture, beyond the June 30, 2020 deadline imposed by AB 1054. PG&E has demonstrated significant failings, and the Commission must take action in new ways to prevent future loss of life and harm and risks to ratepayers.

MCE recommends an appointment of a receiver to PG&E, although it does not make this recommendation lightly. The remedy itself is in many ways a remedy of last resort. However, MCE believes it is appropriate for the Commission to move forward with this remedy; the Commission has the power to do so.[37][38]

A. Receivership Standard Applied to the California Prison System

In 2005, California's prison system was placed into receivership.[39] The case establishing the receivership used the following elements in its test for whether to approve the request for a receiver:

---

[37] Section 701 (Commission Powers), which states: "The commission may supervise and regulate every public utility in the State and may do all things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction."

[38] The venue for the request of the Commission could be in California state court, but more likely with the action in the Bankruptcy Court or in the Federal Court. *United States of America v. Pacific Gas and Electric Company*, Case 14-CR-00175-WHA (PG&E Criminal Probation Proceeding).

[39] The following article provides an overview of the context of that appointment: "Federal Court Seizes California Prisons' Medical Care; Appoints Receiver with Unprecedented Powers," *Prison Legal News*, March 15, 2006. Available at: https://www.prisonlegalnews.org/news/2006/mar/15/federal-court-seizes-california-prisons-medical-care-appoints-receiver-with-unprecedented-powers.

> The decision whether to appoint a receiver is a function of the court's discretion in evaluating what is reasonable under the particular circumstances of the case. [Citations Omitted.] As the case law concerning the receivership remedy for the reform of public institutions has developed over the past few decades, a multi-pronged test has developed to guide the trial courts in making this often difficult determination. The test includes the following elements, the first two of which are given predominant weight:
>
> (1) Whether there is a grave and immediate threat or actuality of harm to plaintiffs;
> (2) Whether the use of less extreme measures of remediation have been exhausted or prove futile;
> (3) Whether continued insistence that compliance with the Court's orders would lead only to confrontation and delay;
> (4) Whether there is a lack of leadership to turn the tide within a reasonable period of time;
> (5) Whether there is bad faith;
> (6) Whether resources are being wasted; and
> (7) Whether a receiver is likely to provide a relatively quick and efficient remedy.[40]

While specifically applicable to public institutions, PG&E's regulation as a public utility make the receivership test as set forth above a reasonable one.

1. Grave and Immediate Threat or Actuality of Harm

The extent of PG&E's harm to Californians is extensively documented.[41] These include:

- Gas explosions:
  - 2010 San Bruno gas explosion
  - 2008 Rancho Cordova gas explosion
- Fires as a result of poor vegetation management:
  - 2019 wildfires, including the Kincade Fire
  - 2017 and 2018 wildfires, including the Camp Fire
  - 2015 Butte fire

---

[40] *Plata v. Schwarzenegger*, 2005 U.S. Dist. LEXIS 43796, *66-67, 2005 WL 2932253.

[41] Exhibit Joint CCA-1 (Beach) at p. 8 lines 5-11.

- 2004 Sims fire and Fred's fire
- 1999 Pendola fire
- 1994 Trauner fire

- Undisclosed groundwater contamination: 1952-1966 Hinkley

PG&E's safety failures are compounded by PG&E records falsification and records mismanagement, posing a grave and immediate threat to the public.

2. Less Extreme Measures of Remediation Have Been Exhausted or Proven Futile

PG&E has faced penalties, court action, monitoring and probation and continues to demonstrate an unwillingness to protect the public from the threat it poses. As discussed above, PG&E has been on felony probation and under investigation by the Commission for years. PG&E has been assigned the largest fine against a utility in the history of this country for the San Bruno Pipeline Explosion.[42] Yet PG&E has persisted in causing catastrophes and loss of life. Less extreme measures have been exhausted and are futile.

3. Insistence with Compliance Would Lead to Confrontation and Delay

PG&E's continued obfuscation and aggressive and deceptive litigation tactics demonstrate that PG&E is either unable or unwilling to change its practices to meet reasonable compliance standards. PG&E admits that full compliance with their existing requirements is not needed and has misled either the probation court or the Commission related to their vegetation management program.[43] This confrontational approach to PG&E's largest existing safety risk indicates that insistence with compliance will be met with confrontation and delay.

[42] D.15-04-024.

[43] See Chapter 2, Section V below.

4. Lack of Leadership to Turn the Tide

PG&E's executives and directors have demonstrated PG&E's ability to evade and to develop "creative interpretations" of the law and the truth.[44] PG&E is beholden to its shareholders alone.[45] This lack of leadership is also evident under the next element of bad faith.

5. Bad Faith

PG&E's deception of the Commission and use of legal maneuvering demonstrate that PG&E is not acting in good faith and is likely to be intentionally acting in bad faith.

PG&E Made a Key Financing Filing the Business Day After PG&E's Relevant Witness Testified. On March 2, 2020, PG&E submitted to the Bankruptcy Court a motion to approve Equity Backstop Commitments and Debt Financing Commitments (the "March 2 Financing Motion).[46]

The March 2 Financing Motion was submitted by PG&E to the Bankruptcy Court only <u>one business day</u> after PG&E Chief Financial Officer (CFO) and witness Jason Wells had taken the stand in the present proceeding.[47] This means that parties to this proceeding were unable to review this agreement or cross-examine the PG&E witness on this key agreement impacting PG&E's

---

[44] *See* Chapter 2 Sections IV, V, and VII in this brief.

[45] *See* Chapter 1 Section I in this brief.

[46] [Dkt. 6013] PG&E Financing Motion dated March 2, 2020. *Debtors' Second Amended Motion for Entry of Orders (i) Approving Terms of, and Debtors' Entry into and Performance under, Equity Backstop Commitment Letters, (ii) Approving Terms of, and Performance under, Debt Financing Commitment Letters and (iii) Authorizing Incurrence, Payment and Allowance of Related Fees and/or Premiums, Indemnities, Costs and Expenses as Administrative Expense Claims* dated March 2, 2020.

[47] Mr. Wells had taken the stand on Friday, February 28, 2020. *See* Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020), pages 516-683.

finances. Mr. Weissmann, counsel for PG&E, stated that this equity backstop commitment letter would not be brought before the CPUC.[48]

Furthermore, objections to the March 2 Financing Motion were due on March 12, 2020. Unlike in other venues, if a party fails to object or reserve its rights by the deadline in the bankruptcy court, the party largely loses its right to later object if additional information comes to light. This motion is scheduled to be heard by the Bankruptcy Court on March 16, 2020 and a decision may occur as soon as that date. This means that the Bankruptcy Court process will conclude prior to reply briefing at the Commission in this proceeding, precluding the insights of the Commission or parties to this investigation from being available to parties in the bankruptcy court.

This appears to be an attempt by PG&E to circumvent Commission jurisdiction and oversight to prevent unreasonable outflows from the holding company. These outflows may not only be impacting the capitalization of the utility but also the ability of the parent company to make necessary capital infusions to the utility as required by the Holding Company Conditions.[49]

PG&E Made Executive Compensation Disclosures the Day After PG&E's Relevant Witness Testified. On March 4, 2020 PG&E submitted to the Bankruptcy Court a motion to approve PG&E's executive compensation plan. ("March 4 Executive Compensation Motion").[50]

---

[48] "PG&E filed an amended equity backstop commitment letter […] referenced in Mr. Wells' testimony. […PG&E is] not proposing to put it in the record. It's a publicly available document." Weissmann (for PG&E), Hearing Transcript Vol. 6 (March 3, 2020), page 1078, lines 12-18.

[49] D.02-01-039.

[50] [Dkt. 6088] *Motion of Debtors Pursuant to 11 U.S.C. §§ 105(a), 363(b), and 503(c) for Entry of an Order Approving Debtors' 2020 (i) Short Term Incentive Plan; (ii) Long Term Incentive Plan; (iii) Performance Metrics for the Chief Executive Officer and President of PG&E Corporation; and (iv) Granting Related Relief.* Objections to this Motion are due in the Bankruptcy Court on March 18, 2020 and PG&E has asked that this motion be heard by the Bankruptcy Court on March 25, 2020.

This occurred only one day after PG&E's relevant witness, John Lowe, took the stand on this exact matter in this proceeding.[51] While this March 4 Executive Compensation Motion is consistent with the submissions in this proceeding,[52] it also makes additional key disclosures that are relevant to this proceeding.

6. Wasted Resources

PG&E's bankruptcy has expended millions, if not billions, of dollars of not only PG&E, but of its counterparties, regulators and victims. Notwithstanding the potential for bankruptcy to reduce costs and reorganize, PG&E plans to emerge from bankruptcy in a non-investment grade credit quality facing significant capital projects necessary to protect ratepayers and the public from further harm. This represents wasted resources that will have lingering effects such as imposing greater financial risks on ratepayers.

7. Receiver Is Likely to Provide a Relatively Quick and Efficient Remedy

While the remedy of a receiver is not likely to provide immediate outcomes, the prospect of actual improvement in PG&E operations, safety and financial condition is likely to be expedited under the receiver paradigm, rather than – as evidenced by PG&E practices and performance – under the influence of PG&E's shareholders. Relative to the status quo,[53] even years would be quick. PG&E has a defensive culture that is resistant to change.[54] Introducing independence into PG&E's operations is likely the most efficient way to address PG&E's serious safety issues.

---

[51] Lowe (PG&E), Hearing Transcript Vol. 6 (March 3, 2020), pages 1165-1173.

[52] *See* [Dkt. 6090] Declaration of Lowe (PG&E) at 8.

[53] *United States of America v. Pacific Gas and Electric Company*, Case 14-CR-00175-WHA (PG&E Criminal Probation Proceeding); *see, also* I.15-08-019.

[54] Exhibit Abrams-1 at p. 9.

B. Venue for the Commission's Request to Place PG&E into Receivership

Receivership is an equitable remedy to be granted by the courts. The appropriate venue would be a federal court, such as *United States of America v. Pacific Gas and Electric Company*, Case 14-CR-00175-WHA (PG&E Criminal Probation Proceeding) before Judge Alsup. The Bankruptcy Court is an alternative if the Commission seeks a Chapter 11 trustee.

IV. BEYOND ANY AB 1054 CONSIDERATIONS, THE PG&E PLAN AND PG&E GOVERNANCE MUST BE FAIR AND REASONABLE

AB 1054 provides that the Commission must "approv[e] the reorganization plan and other documents resolving the insolvency proceeding, <u>including the electrical corporation's resulting governance structure</u> as being acceptable in light of the electrical corporation's safety history, criminal probation, recent financial condition, and other factors deemed relevant by the commission."[55] However, PG&E is failing the basic legal and reasonableness standards that must be met prior to addressing the higher standards set forth by AB 1054.

MCE Recommends that:

- The Commission should immediately order a directed outcome to prohibit PG&E – including PG&E Corporation – from entering into transactions that decapitalize PG&E for the benefit of PG&E's shareholders until such time as:
    - (1) PG&E is in compliance with all financing and holding company requirements, or
    - (2) the Commission has revoked PG&E's holding company authorization and deemed such transactions reasonable.

[55] Section 3292(a)(1)(C).

- The Commission should reject PG&E's aggressive requests for waivers from existing rules, including:
    - PG&E's violation of the first priority condition;
    - PG&E's request for waiver – including permanent waiver – from the Commission's capital structure requirements; and
    - PG&E's request for increase to its short-term debt authorization.
- The Commission should further revoke PG&E's holding company authorization.

A. PG&E Is Abusing the Holding Company Structure

PG&E is subject to a wide range of Commission decisions on the requirements of holding companies and affiliates.[56] These decisions are important to ensure PG&E is financially healthy and does not undermine the strength of the utility for the benefit of the shareholders.

1. PG&E Has Failed to Provide Adequate Information on the Funds of the Utility, Precluding Commission Oversight and Masking Transactions Decapitalizing the Utility

Notwithstanding the significant transparency requirements in the Bankruptcy Court, including the segregation of Corporation and Utility funds,[57] PG&E has failed to disclose the actual financial impact of the transactions contemplated in the PG&E Plan to the Utility. Instead, PG&E has chosen to aggregate the sources and uses under the proposed bankruptcy transaction across the Utility and the Corporation.

---

[56] See, D.97-12-088 (adopting affiliate transaction rules); D.98-08-035 (modifying affiliate transaction rules); D.98-08-035 (adopting enforcement of Affiliate Transaction Rules); D.02-01-037 (defining the "first priority" condition); and D.06-12-029 (further revising the Affiliate Transaction Rules).

[57] See, e.g. Exhibit MCE-X-1, Attachment 3, PG&E Monthly Operating Report dated January 29, 2020, at 35.

PG&E has falsely claimed that it cannot provide to the Commission, the Utility's regulator, a set of sources and uses of the transactions as a result of "securities laws."[58] Notwithstanding this claimed prohibition, PG&E has publicly disclosed in other venues information specifically germane to the issues before the Commission. For example, while the amount of "Holdco Funded Debt" was undisclosed in PG&E's testimony, it was disclosed in the Bankruptcy Court as $650 million.[59] With regards to the Utility Pollution Control (PC) Bond Claims, PG&E simply has provided no information. The Utility PC Bond Claims have unique references and protections throughout the Plan of Reorganization and its supporting documents; however, the scale, impact and importance of those claims are unaddressed in the PG&E Plan. These details are necessary for the Commission to provide adequate oversight of PG&E's proposed exit from bankruptcy.

2. PG&E Has Demonstrated that the Utility Is Undercapitalized and Will Continue to Be Undercapitalized Upon Exit from Bankruptcy, in Violation of the First Priority Condition

As clearly stated by PG&E's Chief Financial Officer: "The company needs to satisfy its capital structure requirements in order to declare a dividend."[60] MCE agrees. Mr. Wells then continues by suggesting that through "adjustments" to the capital structure requirements – including, as Mr. Johnson noted, a <u>permanent</u> waiver of those requirements – PG&E would "become in compliance with this capital structure."[61] MCE disagrees that this is in any way compliance with the capital structure nor that this is an allowable or acceptable outcome.

PG&E's holding company, PG&E Corporation, is required to comply with the first priority condition. This condition states: "The capital requirements of PG&E, as determined to be

[58] Exhibit MCE-X-1, Data Request Response MCE_001-Q01, at 4.

[59] Exhibit MCE-X-1, Attachment 3.

[60] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020), page 547 at lines 1 to 3.

[61] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020), page 547 at lines 3 to 6.

necessary and prudent to meet the obligation to serve or to operate the utility in a prudent and efficient manner, shall be given first priority by PG&E's Board of Directors."[62] PG&E has not made a showing that the first priority condition has been met with regards to their plan. PG&E's Chief Financial Officer in fact is "not familiar with that condition."[63] PG&E's failure to make a showing regarding, much less demonstrate compliance with, the first priority condition is inexcusable.

The Commission, as a Conclusion of Law, has stated that "<u>The implementation of any scheme, whether under a bankruptcy reorganization plan or otherwise, pursuant to which a holding company would unduly benefit, to the detriment of its utility subsidiary and that utility's ratepayers, would be contrary to any reading of the first priority condition</u>."[64] Such a scheme is at issue here.

PG&E has demonstrated that it will not be in compliance with the Commission's capital structure requirements or temporary debt financing authorization limits. PG&E has asked for significant waivers within this proceeding, demonstrating insufficient capitalization of the utility. PG&E has asserted that it "anticipates that the Utility will emerge from bankruptcy with a balanced capital structure that complies with the regulatory capital structure authorized in D.19-12-056"[65] but <u>only if</u> the Commission provides for the following waivers and departures from Commission rules:

---

[62] D.02-01-039 at 5.

[63] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020), page 547 at lines 10 to 11.

[64] D.02-01-039 at 64, Conclusion of Law 8.

[65] Exhibit PG&E-1 (Wells), PG&E Prepared Testimony Volume 1 dated January 31, 2020, at 2-21.

> PG&E's request that "any debt used to finance the initial and annual contributions to the Wildfire Fund [… be] excluded from measurement of the authorized capital structure"[66] PG&E anticipates this to be $2.4 billion in long-term debt. [67]
>
> PG&E's request that "Temporary Utility Debt of $6 billion to pay wildfire claims… [be] excluded from the calculation of the capital structure" [68]
>
> PG&E's request that PG&E's $6-7 billion financings related to "certain Community Wildfire Safety Program capital expenditures with securitized debt […] and any conventional debt financing of these expenditures prior to refinancing debt [… be] excluded from the calculation of the capital structure for compliance and ratemaking purposes." [69]

Importantly, PG&E has noted that these "adjustments":

> apply equally with respect to the ratemaking capital for purposes of the holding company conditions (see D.96-11-017 and D.19-12-056) as well as the affiliate transaction rules (see D.06-12-029 (Rule IX.B.)), <u>including in connection with any dividends</u>. Alternatively, the Commission could issue a waiver from compliance with the authorized capital structure as contemplated in A.19-02-016 for these same purposes." [70]

To translate this for the Commission, PG&E seeks significant waivers from the Commission, leaving the utility financially vulnerable, while still paying out dividends to shareholders. This is patently unreasonable, as explained below.

3. *PG&E's Request for a Waiver from the Commission's Capital Structure Requirements Demonstrates Insufficient Capitalization at the Utility*

The Commission has already determined that the first priority condition incudes, but is not limited to, the utility maintenance of a balanced capital structure.[71] The Commission requirement

---

[66] Exhibit PG&E-7 (Wells), PG&E Supplemental Exhibit with Errata dated February 5, 2020, at 2-22.

[67] Exhibit PG&E-7 (Wells) at 2-22.

[68] Exhibit PG&E-7 (Wells) at 2-22.

[69] Exhibit PG&E-7 (Wells) at 2-22 to 2-22A.

[70] Exhibit PG&E-1 (Wells) at 2-21, footnote 47, emphasis added.

[71] D.02-01-039 at 63, Conclusion of Law 5.

to maintain a balanced capital structure is designed to ensure that PG&E Company and its customers are protected from PG&E's parent or holding company extracting excessive and needed capital from the company.

These protections are needed now. PG&E is achieving such undercapitalization that if it is not authorized its inadvisable securitization proposal, PG&E would seek a permanent waiver in the capital structure:

> Q (President Batjer) We have talked, you have been cross-examined yesterday and today, regarding securitization. If, for whatever reason, we were not able to grant securitization, what is -- what is your plan?
>
> A (CEO Bill Johnson) The next step would be to ask for a permanent waiver in the capital structure.
>
> Q I'm sorry. Say that again.
>
> A A permanent waiver in the capital structure.
>
> Q A permanent waiver?
>
> A Yeah.[72]

4. PG&E's Request for a Waiver from the Commission's Short-Term Debt Limits Demonstrates Insufficient Capitalization at the Utility

This undercapitalization on a debt-to-equity ratio basis is made more concerning by PG&E's request to increase in its authorized short-term debt cap.[73] PG&E's proposed 50% increase of the Commission-authorized short-term debt authorization would increase that limit to $6 billion.[74]

[72] Johnson (PG&E), Hearing Transcript Vol. 2 (February 26, 2020), at 267 line 20 to 268 line 1.

[73] Short-term debt is excluded from the Commission's calculation of debt-to-equity ratio. "The capital structure of an investor owned utility (IOU) is the proportional authorization of shareholders' equity and debt that comprise a company's long-range financing of its capitalization." D.19-12-056 at 6, emphasis added.

[74] Exhibit PG&E-1 (Wells) at 2-26.

The current short-term debt authorization decision, D.09-05-002, states that "The primary standard used by the Commission is whether a utility has demonstrated a reasonable need to issue short-term debt for proper purposes. Where necessary and appropriate, the Commission may attach conditions to the issuance of short-term debt in order to protect and promote the public interest."[75] In this proceeding, PG&E has not demonstrated "reasonable need" nor "proper purposes." As a result, the Commission is not able to determine whether the borrowings would "protect and promote the public interest."

Furthermore, PG&E's request for a waiver relies upon and earlier waiver decision in which PG&E was authorized entry into the Debtor In Possession (DIP) financing which explicitly stated: "The exemption granted in this decision is narrow and only provides PG&E the limited exemption from §§ 823 and 851 for purposes of pursuing DIP financing, as described below, and is conditioned on PG&E making a compliance filing setting forth the terms of the DIP financing."[76] The exemption was made solely as a result of an extraordinary situation[77] resulting from "a substantial risk that the public health and safety of California will be severely impaired with potentially catastrophic results."[78] This extraordinary situation was related to the reality of entering bankruptcy and the challenges with financing a company's operations at its most financially vulnerable moment. The PG&E Plan to rely on waivers means they will be financially vulnerable upon their exit from bankruptcy. This represents both a dangerous risk to ratepayers and a failure to adequately improve PG&E's financial condition through their Chapter 11 bankruptcy process.

---

[75] D.19-02-016 at 2-3.

[76] D.19-01-025 at 2.

[77] D.19-01-025 at 4. "The Commission grants exemptions under § 853(b) only in extraordinary situations." Citing D.03-11-015, at 7.

[78] D.19-01-025 at 6.

5. *PG&E Has Failed to Disclose Material Transactions Impacting the Holding Company Requirements, Including the Terms of the Equity Backstop*

On March 2, 2020, PG&E submitted to the Bankruptcy Court a motion to approve Equity Backstop Commitments and Debt Financing Commitments (the "March 2 Financing Motion).[79] MCE addresses the bad faith timing of these disclosures in Section III.A.5 above. This appears to be an attempt by PG&E to circumvent Commission jurisdiction and oversight to prevent unreasonable outflows from the holding company. These outflows may not only be impacting the capitalization of the utility but also the ability of the parent company to make necessary capital infusions to the utility as required by the first priority condition.

MCE focuses on the Equity Backstop Commitments. The Equity Backstop Commitments are proposed transactions between PG&E Corporation and its major shareholders, including Knighthead Capital Management and Abrams Capital Management.[80] If PG&E is unable to raise equity in the market, it will rely upon these commitments; however, these commitments do more than provide "insurance" to PG&E. [81] Rather, they provide a substantial guaranteed payout to its current shareholders, and an even greater upside to those shareholders. Pursuant to the Equity Backstop Commitments:

> [A]ssuming that the Debtors implement the OII Capital Structure by drawing on the Equity Backstop Commitments and based on the Debtors' forecasted Normalized Estimated Net Income, the value of the Equity Commitment Premium would be approximately $1.2 billion at the currently estimated Equity Backstop

[79] [Dkt. 6013] PG&E Financing Motion dated March 2, 2020. *Debtors' Second Amended Motion for Entry of Orders (i) Approving Terms of, and Debtors' Entry into and Performance under, Equity Backstop Commitment Letters, (ii) Approving Terms of, and Performance under, Debt Financing Commitment Letters and (iii) Authorizing Incurrence, Payment and Allowance of Related Fees and/or Premiums, Indemnities, Costs and Expenses as Administrative Expense Claims* dated March 2, 2020.

[80] [Dkt. 6014] Declaration of Ziman (for PG&E) at 8.

[81] [Dkt. 6014] Declaration of Ziman (for PG&E) at 16 lines 9 to 10.

> Price. The value of the Equity Commitment Premium could exceed this amount in the event that PG&E Corp successfully consummates a marketed equity offering or rights offering in lieu of drawing on the Equity Backstop Commitments or if the Debtors implement a more leveraged capital structure. Based on the closing price of PG&E Corp. common stock on February 28, 2020, the value of the Equity Commitment Premium would be approximately $1.8 billion. Notably, except as described in footnote 2, the Equity Commitment Premium is payable in shares of New PG&E Corp. Common Stock[82]
>
> The referenced footnote provides:
>
> The Equity Commitment Premium is generally payable in stock; however, in the following limited circumstances each Equity Backstop Party may elect to be paid in stock or cash: (i) PG&E Corp. exercises its right to terminate the Equity Backstop Commitment Letters in order to enter into a transaction for the sale of the company or (ii) a plan of reorganization other than the Debtors' Plan of Reorganization is confirmed. If paid in cash, the Equity Commitment Premium would be approximately $764 million (6.364% of the full $12 billion commitment).[83]

These financial outflows are unacceptable in light of the precarious financial position of both PG&E Corporation and PG&E Company. Furthermore, as PG&E Company is insufficiently capitalized, this is a violation of the first priority condition. As set forth in the Ziman Declaration in the bankruptcy court, this Equity Backstop Commitment provides "significant value to the Debtors and the estates, particularly existing shareholders."[84] Another substantial impact is the dilution of share value held in the Fire Victim Trust. As payouts of equity occur under this backstop agreement, it would dilute the shares awarded to compensate fire victims thus reducing the value of already-depressed stock that must rebound before victims can be made whole. This will have the effect of delaying or precluding full compensation to fire victims and enriching existing shareholders.

[82] [Dkt. 6014] Declaration of Ziman (for PG&E) at 8-9, emphasis added.

[83] [Dkt. 6014] Declaration of Ziman (for PG&E) at 8, footnote 2, emphasis added.

[84] [Dkt. 6014] Declaration of Ziman (for PG&E) at 12, emphasis added.

B. PG&E Has Failed to Meet the Holding Company Requirements; PG&E's Holding Company Authorization Must Be Revoked and the Commission Must Take Urgent Steps to Prevent the Further Decapitalization of PG&E

Until such time as: (1) PG&E is in compliance with all financing and holding company requirements, or (2) the Commission has revoked PG&E's holding company authorization and deemed such transactions reasonable; *PG&E should be prohibited from binding PG&E to substantial equity payouts of $1.2 billion to $1.8 billion to its existing shareholders or cash outflows of $764 million as such funds may be needed to sufficiently capitalize the Utility.*

PG&E Corporation and PG&E Company are either unable or unwilling to bring the utility back to a balanced capital structure and have otherwise shown disregard for the financial health of the utility. As such, the Commission must enforce its regulation protecting ratepayers – and the utility itself – from excessive leverage, risk and decapitalization. MCE recommends that *the holding company authorization should be revoked*.

1. PG&E's Aggressive Requests to Maximize Payments to Shareholders Were Deemed Unreasonable and Contrary to the Public Interest in the Last Bankruptcy; the Commission Must Reject PG&E's Even More Aggressive Requests for Waiver and Modification of Commission Requirements Here

During PG&E's last bankruptcy, the Commission modified PG&E's Proposed Settlement Agreement, by:

> deleting Paragraph 6 ("Dividend Payments and Stock Repurchases"), which we find is unreasonable and not in the public interest. Paragraph 6 of the PSA proposes that other than ensuring compliance with the capital structure and stand-alone dividend conditions in D. 96-11-017 and D.99-04-068, the Commission shall not restrict the ability of the boards of directors of either PG&E or PG&E Corporation to declare and pay dividends or repurchase common stock. […] Because it is unreasonable and contrary to the public interest to preclude the Commission from

> considering such challenges, if any, we are exercising our regulatory authority to strike Paragraph 6.[85]

PG&E's requests, which were "unreasonable and contrary to the public interest" in the last bankruptcy, pale in comparison with the requests made in this proceeding and the actions taken and proposed to be taken in the bankruptcy court by PG&E. Here, PG&E does not even propose to comply with the capital structure requirements or the stand-alone dividend provisions, instead it seeks a waiver to both. The waivers to the capital structure requirement and the request to increase the Commission's short-term debt limit should be rejected or set on a strict path forward to remedy these deficiencies.

2. The Commission Should Immediately Order a Directed Outcome to Prohibit PG&E from Entering into Transactions to Decapitalize PG&E for the Benefit of PG&E's Shareholders

PG&E is seeking to hide an immediate dividend payment to its shareholders in the Bankruptcy Court as a "Equity Backstop Agreement." As discussed above in this section, any such action decapitalizing PG&E must be prohibited by the Commission and subject to claw-back as contrary to law and regulation. The Commission must evaluate other transactions protecting existing shareholders, such as the Noteholder Restructuring Support Agreement (RSA), to identify the decapitalization impact of such agreements and include those within the Commission's AB 1054 "neutral, on average" analysis.

3. The Commission Should Revoke PG&E's Holding Company Authorization

PG&E's failures to comply with the Commission's holding company requirements, including the first priority condition, and its actions taken to aggressively decapitalize PG&E

[85] D.03-12-035 at 29-30 (emphasis added).

warrant revocation of PG&E's holding company authorization. This should be done in such a way as to avoid undermining the claims of fire victims that are expected to receive half of their compensation through equity in the holding company. The Commission needs immediate oversight ability and transparency into the operations of PG&E Corporation to prevent further damage to the utility and risk to ratepayers.

V. THE PG&E PLAN AND PG&E'S GOVERNANCE FAIL TO MEET AB 1054 STANDARDS "IN LIGHT OF" PG&E'S SAFETY HISTORY AND CRIMINAL PROBATION

The Commission should find that the PG&E Plan and PG&E's governance as proposed fails to meet the standard of AB 1054 "in light of" PG&E's safety history and criminal probation. This finding will support additional and needed oversight of PG&E as discussed in Chapter 3 below.

A. PG&E Is Evading Compliance with its Conditions of Probation

PG&E has created a sorites paradox of compliance. PG&E has absurdly defined compliance as something less than "perfect compliance.". In essence PG&E has determined that "perfect" compliance isn't possible, so they consider "substantial compliance" still compliant. But such an approach does not answer at what point PG&E is actually non-compliant. Such an absurd claim is an admission of non-compliance and should not be accepted as anything more.

PG&E's Chief Ethics and Compliance Officer defined this absurd premise of compliance:

> Q (Kelly) And is PG&E currently in compliance with applicable vegetation management and clearance-related laws? […]
> A (Kane) So, we believe we are in substantial compliance. What we are not comfortable doing is certifying perfect compliance because of the […] very dynamic nature of our service territory which has millions of trees and thousands of individuals working to ensure that we do adhere to veg management and clearance-related laws and the fact that at any given moment in time, in fact even after an inspector has just looked at a tree or someone has just trimmed a tree because of natural occurrences in the environment; as an example, winds blowing which brings a branch close – […] ·In any case, because conditions can change so quickly and the environment is so dynamic that for us to certify that any given tree

is in compliance with let's say a clearance standard would be impossible.· We would have to actually have people posted at each tree day and night all the time and we just can't comfortably do that.· So rather than certify perfect compliance, we are stating that we are in substantial compliance.[86]
[…]

When pressed, PG&E demonstrated that it is simply unwilling or unable to define what substantial compliance is for purposes of their own operations:

Q (Kelly) How does PG&E define "substantial compliance?"· I would assume that in order to say, "we're in substantial compliance," PG&E has determined what substantial compliance means to PG&E. Can you define what that is?
A (Kane) I don't think I am the best person to define it. Maybe you can talk to the wildfire people. What I do know is the vast majority of the work that we attempted to complete last year to comply with this requirement was completed.[87]

Q (Kelly) So who defines what is substantial compliance?
A (Kane) All I can tell you is I do not.[88]

To further lower the bar, PG&E's Chief Executive Officer stated: "We've had some compliance issues, so for us to say we stand by the law is a good thing."[89] PG&E saying it supports the law, and actually following it are two different things. The former cannot stand in for the latter.

Furthermore, PG&E has argued that its Enhanced Vegetation Management (EVM) program would not reduce the frequency of PSPS before Judge Alsup,[90] but when asked before the Commission, and only when pressed, PG&E stated that it did.

[86] Witness Kane, Chief Compliance Officer for (PG&E,), Hearing Transcript Vol. 5, (March 2, 2020), at 824 line 4 to 826 line 4.

[87] Witness Kane, Chief Compliance Officer for (PG&E,), Hearing Transcript Vol. 5, (March 2, 2020), at 826, lines 10-21.

[88] Witness Kane, Chief Compliance Officer for (PG&E,), Hearing Transcript Vol. 5, (March 2, 2020), at 836, lines 14-16.

[89] Johnson (PG&E), Hearing Transcript Vol. 1 (February 25, 2020), at 157 lies 1-3.

[90] Order to Show Cause Hearing, Wednesday, February 19, 2020 (counsel for MCE was in attendance):

Q (Kelly) So just to clarify, [… b]etween normal weather conditions and some - let's call it - upper limit threshold, is it true that there would be a reduction in PSPS?

A (Vesey) Yes.[91]

B. PG&E Appears to Be Misrepresenting the Effects of the EMV Program to the Probation Court, Perhaps in Hopes of Avoiding Additional Probation Requirements; PG&E Ignores the Most Serious Red Flags of the Probation Monitor in its Testimony

PG&E is also misleading the Commission by failing to disclose significant observations by the probation monitor. PG&E's view of the Monitor Letter sent to Judge Alsup on July 26, 2019 is materially misleading:

> In August 2019, the Utility received a copy of a letter report from the Monitor to the Court on his team's vegetation management field inspections, in which the Monitor preliminarily observed that the Utility's contractors had missed some trees that should have been identified and worked under the Utility's Enhanced Vegetation Management Program, and that the systems for tracking and assigning such work may have contributed to the missed work. Notably, the vast majority of the potential missed trees were missed only in the sense that they arose under the aggressive standards that the Utility voluntarily chose to adopt in its Program, and that went beyond the minimum requirements imposed by law; such misses do not indicate violations of state or federal regulations.[92]

However, the Monitor team had found 61.32 exception trees per mile, including 1.14 potential hazard trees per mile. These hazard trees were each violations of Public Resources Code

---

Judge Alsup: But don't you admit that if you were in full compliance with your own mitigation plan and with the state law, that there would be fewer times that you would need to do - resort to PSPS?

Orsini (for PG&E): No, Your Honor.

[91] Witness Vesey, CEO and President of the Utility, Hearing Transcript, Vol. 3 (February 27, 2020) at 483, lines 19-25.

[92] Exhibit PG&E-1 (Kane), at 8-18 line 23 to 8-19 line 1.

Section 4293 and were accompanied by a finding that "most potential hazard tree exceptions… were not properly documented… or marked." [93]

The Monitor Letter also informed Judge Alsup that "during the first 10 weeks of field inspections the Monitor team as notified PG&E of three urgent potential exceptions that could have resulted in fatalities, injuries or serious damage."[94] These three were:

> (1) "a tree that was within one foot of a primary conductor, despite being marked as 'tree work complete'";
>
> (2) "a tree that was in contact with a primary conductor"; and
>
> (3) "a tree within inches of the primary conductor, and had been contacting the conductor during wind gusts. [… A] tree work company reported to PG&E that it completed the work… even though it was not actually completed." [95]

To be clear, two of these three urgent exceptions involved improper recordkeeping. The Monitor found:

> The VM (vegetation management) inspections are not only revealing individual trees that are missed, including three active wildfire threats in high risk areas, but they also reflect gaps in processes (for example, contractor training) and other issues bearing on the overall efficacy of the VM program (for example, systemic recordkeeping deficiencies). Of course, five of PG&E's felony convictions from the 2016 trial related to record-keeping defects concerning its gas operations. [96]

C. PG&E Has Stated That It Will Comply with the PG&E Plan Safety Commitments "When Ordered by a Judge or a Regulator"

PG&E provides no assurances to fulfill the safety promises in the PG&E Plan.

> Q (Strauss) Is there anything in place that ensures that the safety commitments are being made now won't be changed in the future?

[93] Exhibit TURN-1A, Appendix F, Monitor Letter sent to Judge Alsup on July 26, 2019, at 19-20 (emphasis added).

[94] Exhibit TURN-1A, Appendix F, at 15.

[95] Exhibit TURN-1A, Appendix F, at 15-16.

[96] Exhibit TURN-1A, Appendix F, at 18 (emphasis added).

> A (Brownell) Well, I think once you've committed, been ordered by a judge or a regulator, or committed in a settlement and there will now be a public document that we can all agree on and track, it would be very difficult without giving some justification to either change, which you couldn't arbitrarily do, nor would you want to. You might in collaboration with others, like the Commission, say we think this would be a better way to go about that.[97]

However, even when ordered by a judge, PG&E is not fulfilling its safety commitments. The litany of safety concerns set forth in the record of this proceeding may be compared with the PG&E Plan which only states that PG&E "intends to comply with the conditions [of probation] going forward" and "anticipates and intends [… to] continue with the extensive probation efforts described above."[98]

VI. THE PG&E PLAN AND GOVERNANCE ARE NOT REASONABLE AND FAIR "IN LIGHT OF" PG&E'S RECENT FINANCIAL CONDITION

The Commission should find that the PG&E Plan and PG&E's governance as proposed fail to meet the standard of AB 1054 "in light of" PG&E's recent financial condition. This finding will support additional and needed oversight of PG&E as discussed in Chapter 3 below.

A. The PG&E Plan that Results in the Utility Being Non-Investment Grade Is Not Reasonable

PG&E in its testimony stated that the PG&E Plan of Reorganization "will successfully resolve the Chapter 11 cases in a manner that […p]ositions the Utility and PG&E Corporation to be financially healthy upon emergence."[99] The evidence demonstrates that this is not true. The Utility, were it to pursue unsecured debt, would have a credit rating designated non-investment grade speculative. The following compares the PG&E Plan outcomes to the credit ratings of average investor-owned utilities in the United States:

[97] Brownell (PG&E), Hearing Transcript Vol. 4 (March 28, 2020), at 733, lines 2-16.

[98] Exhibit PG&E-1 (Kane), at 8-21 line 25 to 8-22 line 4.

[99] Exhibit PG&E-1 (Wells) at 2-1.

Entity	Credit Rating	Description
PG&E Company (Utility)		
Secured Debt	BBB or BBB-[100]	Lower Medium Investment Grade
Unsecured Debt	“Mid- to high-BB”[101]	Non-Investment Grade Speculative
Combined PG&E Utility and HoldCo	“In the BB category”[102]	Non-Investment Grade Speculative
Average Investor-Owned Utility in the United States		
Secured Debt	BBB+ or A-[103]	Lower Medium Investment Grade to Upper Medium Investment Grade
Unsecured Debt	BBB+ or better[104]	Lower Medium Investment Grade or better

PG&E’s non-investment grade rating will either lead to higher financing costs in the form of interest rates or additional collateral or security that must be pledged. This represents a cost to ratepayers and *must be accounted for in the Commission’s process to ensure rate neutrality*.

VII. THE FINANCING AUTHORIZATIONS REQUESTED BY PG&E ARE NOT SUBSTANTIATED BY LAW OR THE RECORD AND SHOULD BE DENIED

With regards to the financing authorizations requested by PG&E, the Commission must:

- Deny any transaction that violates Section 701.5 which prohibits a utility from providing a guaranty to its holding company;

[100] Plaster (for PG&E) Hearing Transcript Vol. 2 (March 26, 2020), at 279 lines 20-22.

[101] Plaster (for PG&E) Hearing Transcript Vol. 2 (March 26, 2020), at 279 24-25.

[102] Plaster (for PG&E) Hearing Transcript Vol. 2 (March 26, 2020), at 290at 16-17.

[103] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020), at 523 Lines 23-24.

[104] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020), at 524 Lines 8-9.

- Deny or require expedited cure for any failure to comply with Rule 3.5 which provides the Commission with necessary information to make a determination on any debt proposed; and
- Reject all improper uses of financing funds, including any funds transfers from the Utility to the Corporation or to shareholders in violation of the "first priority condition."

A. PG&E Has Not Met the Basic Financing Requirements Set Forth in Rule 3.5 and Section 701.5

Rule 3.5 of the Commission's Practice and Procedure identifies the extensive requirements that must be met in a request for authorization of financing. *PG&E has not complied with this rule and therefore the request for authorization of financing should be denied or cured.*

Furthermore, PG&E has not complied with Section 701.5 which provides (emphasis added):

> [N]o electrical, gas, or telephone corporation, whose rates are set by the commission on a cost-of-service basis, shall issue any bond, note, lien, guarantee, or indebtedness of any kind pledging the utility assets or <u>credit for or on behalf of any subsidiary or affiliate of, or corporation holding a controlling interest</u> in, the electrical, gas, or telephone corporation." These are discussed with each transaction set forth below.

In addition, the uses of funds, in some cases, is prohibited, as described below.

B. $11.85 Billion in Long Term Noteholder RSA Debt ("New Noteholder RSA Debt")

PG&E requests to enter into $11.85 billion in long-term <u>secured</u> debt as contemplated by the Noteholder RSA and according to the terms described therein.[105] This New Noteholder RSA Debt would replace the <u>unsecured</u> debt reflected in the Financial Statement of PG&E dated

[105] Exhibit PG&E-1 (Wells) at 2-3; Exhibit PG&E-2 (Wells), PG&E Prepared Testimony Volume 2 dated January 31, 2020, Attachments 2.6 and 2.7 reflect this debt.

September 30, 2019[106] and the "Use" entitled "Prepetition Debt" in Table 2.3 of Mr. Wells's testimony.[107]

MCE Recommends with regard to the 11.85 Billion in Long Term Noteholder RSA Debt ("New Noteholder RSA Debt"):

- The Commission should deny the conversation of unsecured to secured debt by PG&E under the Noteholder RSA without any benefit to ratepayers.
- If the Commission approves the transaction, the Commission should find that the "contributions of ratepayers" includes the differential in interest rates between secured and unsecured debt.

1. The Conversion of Unsecured Debt to Secured Debt Raises Risks to Ratepayers and Victims in the Event of Future Material Events at PG&E and Should be Rejected

As the New Noteholder RSA Debt would be fully secured, this would mean that if any major safety incident or loss of life were to occur and PG&E were responsible, any victims would be second in line after this debt. Additionally, these secured creditors would have a much larger interest in the physical assets of the PG&E, which is a risk for ratepayers that require those assets for electricity service. Finally, PG&E's choice to use its assets as security means PG&E will have little capacity to raise debt at all, let alone at favorable rates, to pay for a large unanticipated liability. As with San Bruno and under SB 901, the ratepayers are positioned to cover any amounts the utility is not able to pay without triggering a credit downgrade. These ratepayer risks represent ratepayer contributions to the PG&E Plan and cannot be ignored.

---

[106] Exhibit 2.1 set forth within Exhibit PG&E-2 (Wells).
[107] Exhibit PG&E-1 (Wells) at 2-16.

2. Ratepayers Must Be Made Whole for the Difference in Market Rate for Secured and Unsecured Debt

As the Commission evaluates "neutral, on average" and "contributions of ratepayers," this conversion of debt must be viewed in light of (1) the difference in interest rates applicable to secured and unsecured debt, meaning ratepayers should be paying less with the assets of the company secured; and (2) the Noteholder RSA being a deal made by current PG&E shareholders to preserve their equity. As clearly stated in the Noteholder RSA, the main consideration given for the agreement was the agreements to:

> (i) support the Amended Plan, (ii) withdraw the Alternative Plan, (iii) suspend the Reconsideration Motion, (iv) withdraw all discovery issued in connection with the Exit Financing Motion and support the granting of all relief requested in the Exit Financing Motion, and (v) withdraw all briefing with respect to the Subrogation Claim impairment issues "[108]

Ratepayers must be made whole for each consideration and the difference in interest rates that ratepayers should have received, by taking the market rate at each rating level and determining the differential between the two for the scale of this facility. That amount should be designated as a ratepayer contribution and disallowed for rate recovery through the process discussed in Chapter 2, Section II above.

C. Up to $11.925 Billion Total in Additional Short-Term Debt and/or Long-Term Debt ("New Additional Utility Debt") Must Be Denied or Revised

Mr. Wells (PG&E) testified at hearings that PG&E's separate requests for $11.925 billion in each for additional short-term debt and additional long-term debt is for a total sum not to exceed $11.925 billion, together the "New Additional Utility Debt". [109]

---

[108] Exhibit 2.5 set forth within Exhibit PG&E-2 (Wells), PG&E Prepared Testimony Volume 2 dated January 31, 2020, at 2 (also labeled 2-Exh.2.5-2).

[109] Exhibit PG&E-1 (Wells) at 2-3, lines 25-29 – identified as request (2) and request (4) in that paragraph.

MCE Recommends with regard to the $11.925 billion total in additional short-term debt and/or additional long-term debt ("New Additional Utility Debt") that:

- To the extent the Commission authorizes the Additional Short-Term Debt or the New Additional Utility Debt, the Commission should authorize no more than $11.925 billion total under these two borrowing segments;
- The Commission should require additional disclosures regarding the refinancing of Pollution Control Bonds, including the counterparties of the proposed transaction and any and all associated claims, including, but not limited to. PC Bond (2008 F and 2010 E) [110] and the value of those associated claims;
- The Commission should reject the Temporary Utility Debt as it proposes a guaranty of Utility assets for the benefit of the holding company in violation of Section 701.5; and
- The Long-Term Debt authorization request must be denied as it fails to contain any terms and conditions, term sheets or other information necessary for the Commission to make a determine, in violation of Rule 3.5.

1. Short Term Debt

PG&E has requested additional short-term debt to finance PG&E's Plan and subsequent exit from Chapter 11.[111] This is broken into three components:

[110] Plan of Reorganization, Section 1.143.

[111] Exhibit PG&E-1 (Wells) at 2-3.

Sources Table 2.2	Amount	Term Sheet / Commitment Letter
Refinancing of Pollution Control Bonds	$0.1 billion	None
New Debt	$5.825	None
Temporary Utility Debt	$6 billion	Bridge Commitment Letter, Exhibit 2.8[112] Note: To be used to pay fire victims but will be the responsibility of the shareholders. PG&E seeks to eventually replace this debt with $7 billion in ratepayer securitization.

PG&E intends to either refinance this short-term debt with long-term debt or with PG&E's ratepayer securitization request.[113]

In reviewing the sole term sheet provided by PG&E, MCE encountered several troubling – and prohibited – terms. These are primarily found in the "Mandatory Prepayments and Commitment Reductions" section.[114] These concerning provisions include: (1) prepayment and commitment reductions in the event of receipt of insurance and condemnation proceeds and intercompany transfers, (2) mandatory prepayment of the Corporation's debt at the same time as the Utility debt, and (3) undefined cross-defaults for material indebtedness.[115]

Each of these Utility loan provisions in different ways acts as a guaranty for the "sister financing" being undertaken by the Corporation. For example, if the Utility were to receive an insurance pay-out it would be required to pay down this facility and the "unsecured" facility of the

[112] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020), at 539 line 21.

[113] Exhibit PG&E-1 (Wells) at 2-3, lines 26-28.

[114] Exhibit PG&E-7 (Wells) at 2-Exh.2.8-26 *et seq*.

[115] Exhibit PG&E-7, 2-Exh.2.8-26, -27 and -33.

Corporation. It would further leave PG&E without the insurance funds. The mandatory prepayment of the Corporation's debt at the same time as the Utility's is also a guaranty. The Commission has no assurance that the Corporation independently has the funds to concurrently fund this requirement and the Corporation's source of income to pay this is dividends from the Utility. As a result, if the Corporation cannot pay, the Utility is "on the hook." The material cross-defaults provision raise this issue as well. Any cross-default between the Company and the Corporation's debts would be an impermissible guaranty.

The result of these provisions is that these so closely tie the Utility Temporary Utility Debt with the PG&E Corporation Debt, acting as a "bond, note, lien, guarantee, or indebtedness of any kind pledging the utility assets or credit for or on behalf of any …corporation holding a controlling interest in, the electrical, gas, or telephone corporation."[116] MCE loosely defines this as a "guaranty." It is important to note that it is not simply a pledge of the utility's assets, but also the utility's credit.

Mr. Wells confirmed that both the $6 billion PG&E Company facility (see Term Sheet) and the $5.825 billion PG&E Corporation facility (no term sheet provided) would be the responsibility of the Company until the debt is able to be refinanced.[117] The Temporary Utility Debt is a violation of Section 701.5 and must be rejected.

2. Long Term Debt

PG&E seeks to utilize long-term debt in addition to or to replace the short-term debt above. Specifically, PG&E seeks authority to enter into secured debt securities, unsecured debt securities,

[116] Section 701.5.

[117] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020), at 551, lines 22-27.

direct loans and accounts receivable financing.[118] No term sheets or commitment letters have been provided with regard to these instruments. This is prohibited pursuant to Rule 3.5.

D. Up to An Additional $6 Billion in Short-Term Debt

The Commission must deny PG&E's request for "up to an additional $6 billion in short-term debt as it has no terms and conditions, term sheets or information necessary for the Commission to make a determination in violation of Rule 3.5.

PG&E has requested short-term debt authority for the Utility's working capital and short term debt needs for exit from bankruptcy and ongoing working capital and short term needs and contingencies after exit[119] This is not reflected on the Sources and Uses Tables.[120] PG&E has "not finalized the negotiations" for this $6 billion in short term authorization request and did not provide term sheets, again in violation of Rule 3.5.[121]

E. The Commission Should Make Clear that Certain PG&E Revenues, Including CCA Pass-Through Revenues and Public Purpose Charge Program Revenues Are Not Encumbered Under Any Securitization Proposal

As committed by PG&E in hearings,[122] the Commission should ensure that any securitization proposal exclude CCA revenues and other excluded revenues consistent with the Final Order regarding Customer Programs, including Pubic Purpose Programs.[123] These Customer Programs are defined in the associated Motion of the Debtors, and include (i) Deposit and Reimbursement Programs, (ii) Public Purpose Programs, (iii) Environmental Cleanup Programs,

[118] Exhibit PG&E-1 (Wells) at 2-29 to 2-31.

[119] Exhibit PG&E-1 (Wells) at 2-3.

[120] *See* Exhibit PG&E-1 (Wells) at 2-16 and 2-17.

[121] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020), at 541 line 22-25.

[122] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020) at 520 line 26.

[123] [Dkt. 843] Final Order regarding Customer Programs, including Pubic Purpose Programs.

(iv) Third-Party Programs, which includes CCA, (v) GHG Credit Programs, and (vi) Customer Support Programs. *The Commission should issue an order to ensure PG&E will not pledge these revenues as security for debt.*

VIII. FINES AND PENALTIES

The Order Instituting Investigation in this proceeding identified as an issue whether a proposed plan of reorganization provides satisfactory resolution of claims for monetary fines or penalties for PG&E's pre-petition conduct.[124] While the Bankruptcy Court has determined that the pre-petition wildfire claims have been "satisfied" as required by P.U. Code Section 3292(a)(1)(B), the Commission must ensure that PG&E commits, on an enforceable basis, that fines and penalties: (1) will paid in full, including for pre-petition conduct not yet penalized, including with regard to the Tubbs Fire; and (2) do not reduce amounts to be contributed into the Fire Victim Trust or otherwise reduce fire victim recovery.

A. PG&E Must Commit, on an Enforceable Basis, that Fines and Penalties Will be Paid in Full and Will Be Allowed for All PG&E Pre-Petition Conduct, Even After PG&E's Emergence from Bankruptcy

PG&E's Plan of Reorganization requires "CPUC Approval" which includes "(c) satisfactory resolution of claims for monetary fines or penalties under the California Public Utilities Code for prepetition conduct." [125] While PG&E requests that the Commission determine that the PG&E Plan provides for satisfactory resolution of claims for monetary fines or penalties,[126] PG&E has been careful to not state that the plan provides for <u>full</u> payment of fines

[124] Order Instituting Investigation at 7.

[125] Section 1.37 of Plan of Reorganization.

[126] Exhibit PG&E-1 (Kenney), at 11-6.

and penalties. When asked directly about whether fines and penalties would be paid in full, PG&E failed to respond to the question asked:

> QUESTION 6
>
> Please provide a breakdown for each PG&E penalty or fine proposed to be levied against PG&E (in I.19-06-015, I.18-12-007, I.15-11-015, and I.18-07-008) and identify whether the amounts payable thereunder would be paid in full by PG&E's shareholders including on what time horizon. If the response is anything other than an unequivocal yes, please explain.
>
> QUESTION [sic] 6
>
> PG&E objects to this request to the extent that it is overbroad and vague and ambiguous. Subject to its objections, PG&E responds as follows:
>
> Shareholders have paid or will pay these fines and penalties when due per the Commission.[127]

Furthermore, the Plan of Reorganization Section 10.3 provides that any person "shall be deemed to have forever waived, released, and discharged the Debtors, to the fullest extent permitted by section 1141 of the Bankruptcy Code, of and from any and all Claims, Interests, rights, and liabilities that arose prior to the Effective Date."

As a result, the Commission must ensure that it is able to impose and collect all fines and penalties, including with regards to the Tubbs Fire, the Kincade Fire and all other conduct, including unknown conduct that has occurred. As such, the Commission should take protective measures to ensure such fines and penalties, if appropriate, and necessary investigations are not barred after PG&E emerges from bankruptcy.

[127] Exhibit MCE-X-1 (Wells), PG&E Response to Data Request MCE_001-Q06.

B. PG&E Must Commit, on an Enforceable Basis, that Fines and Penalties Will Not Reduce Fire Victim Trust Amounts

Fines and penalties are to be included in the total capped amount of the Fire Victim Trust.[128] This means, without Commission precautions, amounts due from PG&E would actually be taken from fire victims.

This issue has been identified by the Commission as reflected in the Presiding Officer's Decision in the Order Instituting Investigation on PG&E 2017 Fires ("Presiding Officer's Decision).[129] With regards to the fine applied therein, the Presiding Officer's Decision states: "$200 million shall be in the form of a fine payable to the General Fund <u>out of funds that would not otherwise be available to satisfy the claims of wildfire victims</u>."[130]

This was stated artfully by PG&E within that proceeding: "The Settlement reflects the reality of PG&E's financial constraints. The decision to forgo seeking rate recovery for $1.625 billion in wildfire-related expenditures imposes a cost on shareholders while preserving PG&E's ability to make victims whole. To put it plainly, the Settling Parties determined that PG&E should use its finite cash resources to prioritize the payment of wildfire victims rather than the General Fund."[131] *The Commission should order PG&E to pay fines and penalties in full without reducing Fire Victims Trust amounts.*

---

[128] See the definition of "Fire Claims" which includes "fines and penalties." (Plan of Reorganization Section 1.75(j)). Such amounts are included in the cap of the Fire Victim Trust pursuant to the Tort Claimants RSA (restructuring support agreement).

[129] D._______ (decision number to be assigned) in I.19-06-015, dated February 27, 2020.

[130] D._______ (Presiding Officer's Decision) at 2, 34, 39, 47 and 73, emphasis added.

[131] PG&E Reply Comments on January 31, 2020 on the Proposed Settlement Agreement (I.19-06-015) at 9.

CHAPTER 3. COMMENTS ON ASSIGNED COMMISSIONER PROPOSALS

I. OVERVIEW

MCE recommends that the Commission expand the scope of the ACR proposals beyond its primary focus of safety. Safety is essential, but in PG&E's case, safety is a symptom of a root causes. These issues include management and governance structures that are misaligned with the public interest, a self-interested approach to providing utility service, and PG&E's belief that it can act with impunity. The Commission should expand the focus of the safety-specific ACR proposals to also include steps toward achieving financial health of the utility, compliance with law and ethical standards and development of a culture aligned with the public interest.[132]

II. PROPOSAL #4 BOARD OF DIRECTORS

With regard to PG&E's Board of Directors, MCE recommends that:

- Directors not be shared extensively between the Corporation and the Company; and
- All Directors should be required to be residents in PG&E service territory during their tenure.

[132] At this time, MCE does not provide comments on the following proposals: Proposal #1 Executive-Level Risk and Safety Officers; Proposal #2 Independent Safety Advisor; Proposal #3 Expanded SNO Committee Authority; Proposal #5 Approval of Senior Management; and Proposal #8 Earnings Adjustment Mechanism. MCE reserves its right to reply to comments to these proposals as it deems appropriate.

A. Directors Should Not Be Extensively Shared Between the Corporation and the Company

> ACR Proposal: "PG&E's board of directors should be comprised of the same directors as PG&E Corporation's board of directors plus one additional director who should be the CEO of PG&E."

To the extent PG&E continues to maintain a holding company structure, *the Board of Directors of PG&E Corporation and PG&E Company must reduce their overlap*. The current director-sharing paradigm has placed the utility at risk as a result of the holding company inappropriately extracting value from the Utility, as they propose to do through the PG&E Plan. Preserving separate boards with separate members, until such time as the holding company is consolidated with the utility, will improve the independence of the utility and helps to ensure that it is considering its risks and long-term capital needs – not simply short-term profits – prior to any weakening of the credit, capital structure or safety measures at the Company. While this will require effort of communication between the entities, the Company is more likely to focus on the specific challenges it faces as a utility, rather than on short-term metrics. With these distinctions, each board would be able to have distinct skills matrices that reflect the actual operations of those entities.

B. All Directors of PG&E Should Reside in PG&E While They Serve on the Board

> ACR Proposal: "At least 50 percent of the directors should be California residents at the time of their election."

The privilege of serving on the board of one of the nation's largest utilities should require residence within the utility's service area. Elected officials are required to live within the communities they serve, and PG&E board members should be no different. PG&E's operations have tremendous impacts on the financial wellbeing and safety of its customers. PG&E's recent wildfires and public safety power shutoffs directly affected millions of Californians. To strengthen the incentives for the PG&E board to act in the public interest, they should be required to live in the communities they serve and impact. A director working from another state is not able to truly appreciate what it is like to experience days of smoke exposure, the palpable or realized threat of wildfires, and days without electricity from a Public Safety Power Shutoff. Such a director would not understand the profound impact these events have on the lives of PG&E customers, nor would they interact with those customers on a day-to-day basis. These greater local insights from a physically present board member will increase the probability that the board will prioritize safety, ethics, and the public interest.

This proposal would not overly limit the pool of talent available to serve on PG&E's board. The residency requirement would only be imposed while the member is serving on the board. As a result, PG&E could still bring in expertise from outside of the service territory, so long as those individuals agree to reside in PG&E's service territory for the duration of their board term.

III. PROPOSAL #6 REGIONAL RESTRUCTURING

With regard to regional restructuring, MCE recommends:

- The Commission ensure that the PG&E Plan and the Regional Restructuring not preclude or preempt any other Commission-led restructuring of PG&E, including the process to make PG&E a wires-only company for electricity service;
- The Commission explore splitting PG&E into affiliates along functional and geographic lines.

A. Regional Restructuring should bring PG&E management closer to the customers they serve while not precluding other structural changes at PG&E that may be needed

> ACR Proposal: "Unless determined otherwise by the Commission, PG&E should create local operating regions to bring management closer to the customers they serve. By June 30, 2020 PG&E shall file an application for approval of a proposed regional restructuring plan […].

MCE shares the Commission's interest in bringing PG&E management closer to the customers they serve. PG&E needs to focus on the safe, reliable, and affordable operations of their system. PG&E's proposal for regional restructuring in the PG&E Plan may be an appropriate tool to effect that change. However, the proposal has unknown costs and should not be allowed to preempt or preclude any other action the Commission may take to restructure PG&E.

AB 1054 requires the PG&E Plan be neutral to ratepayers.[133] PG&E has not defined the costs associated with the regional restructuring element. Instead, PG&E plans to file a separate application on Regional Restructuring at the Commission. Even if the Regional Restructuring plan is the most cost-effective way to align PG&E with the public interest, the costs are still relevant to AB 1054 and must be included in the assessment of ratepayer contributions and rate neutrality. The Commission should identify any costs associated with Regional Restructuring and include them in the subsequent analysis of rate neutrality proposed in this brief.[134]

For years, the Commission[135] and the courts[136] have been exploring ways to reform PG&E into a safe company with input from stakeholders. The PG&E Plan and the Regional Restructuring element should not be allowed to preclude or preempt any other Commission-led restructuring of

[133] AB 1054.

[134] *See* Chapter 2, Section II.

[135] See, generally, I.15-08-019.

[136] *United States of America v. Pacific Gas and Electric Company*, Case 14-CR-00175-WHA (PG&E Criminal Probation Proceeding).

PG&E. As discussed above,[137] the Commission should commence a process to make PG&E a wires-only company for electricity service. The Commission should also explore splitting PG&E into affiliates along functional and geographic lines. There are important options the Commission should not take off the table through approval of the PG&E's requested moratorium.[138] The Commission should disregard PG&E's request for a moratorium and move ahead with structural changes needed to serve the public interest.

IV. PROPOSAL #7 SAFETY AND OPERATIONAL METRICS

> ACR Proposal: "In the appropriate Commission proceeding, PG&E should propose attainable Safety and Operational Metrics that, if achieved, would ensure that PG&E provides safe, reliable and affordable service consistent with California's clean energy goals ("Safety and Operational Metrics"). These metrics will be subject to Commission review, revision, and approval. The Safety and Operational Metrics should be consistent with state law and include metrics that measure progress over defined periods of time in order to ensure that the PG&E is meeting its obligations to the state of California. The Commission may use any approved metrics to measure PG&E's progress on critical safety issues."

MCE recommends that:

- PG&E's safety and operational metrics include performance-based metrics to measure progress toward safety, affordability, reliability, equity, and climate outcomes to strengthen the shareholder interest in achieving those outcomes;
- PG&E be precluded from defining the appropriate metrics, rather this should be performed in the fully transparent environment of the Commission.

MCE supports the Commission's effort to establish Safety and Operational Metrics to measure PG&E's success. PG&E must be held accountable to verifiable binding commitments and measurable metrics, applied to all levels of the organization, and tailored to the applicable level of

[137] *See,* Chapter 2, Section I.

[138] Plan of Reorganization, Section 1.37.

the organization.[139] PG&E should attempt to quantify the risk associated with its equipment and operations in ways that can be embedded in metrics and tracked toward success. PG&E must have performance-based metrics to measure progress toward safety, affordability, reliability, equity, and climate outcomes to strengthen the shareholder interest in achieving those outcomes.

However, PG&E should be precluded from defining these metrics as they have demonstrated, including in this proceeding, that they will set exceedingly low standards to achieve. For example, in PG&E's Wildfire Safety Plan, the quality assurance standard for tree-trimming in high threat fire districts (HTFD) was only achieving a standard of "92 percent 'meets expectations.'"[140] This means that PG&E could miss 8% of trees required to be trimmed in a HTFD. This exposes customers and Californians to extreme risk.

V. PROPOSAL #9 EXECUTIVE COMPENSATION

With regards to executive compensation, MCE recommends that:

- PG&E's executive compensation metrics be developed under the oversight of the Commission;
- The Commission ensure compensation arrangements are public;
- The focus on "financial performance" in PG&E's metrics must instead be "financial health";
- 95% of incentive payments should be tied to safety outcomes
- Incentive payments should be prohibited if PG&E causes a safety incident that results in any fatalities.

[139] Exhibit Abrams-1 at p. 14-15.

[140] Exhibit MCE-X-2, Pacific Gas and Electric Company Amended 2019 Wildfire Safety Plan dated February 6, 2019.

- Incentive compensation for all employees, including the CEO, be comprised of short-term and long-term incentives. Such incentives must be based upon the financial health and operatorial outcomes (including safety) of the utility, not shareholder-focused metrics such as earnings per share.

A. Executive Compensation Criteria Should Be Developed in the Transparent Environment of a Commission Proceeding; PG&E Should Not Be Trusted to Develop These on Their Own

PG&E's executive compensation metrics must be developed under the oversight of the Commission. PG&E's easily achievable targets and failure to address real outcomes demonstrate that this is necessary. For example, PG&E states that their executive compensation is based on 75% safety. That metric, while *technically* true, on a substantive basis is entirely inadequate. Each sliver of safety is broken down into sub-components such that PG&E would have to have serious deficiencies in eleven different safety areas for compensation to be reduced by the full 75%, while still excluding vast areas of risk, including gas explosions and PSPS events resulting in environmental danger or loss of life. Furthermore, the standards PG&E sets for itself in achieving goals is far too low and, frankly, off the mark.

B. Greater Transparency with Regard to Executive Compensation Is Necessary

> ACR Proposal: "Publicly disclosed compensation arrangements for executives; Written compensation agreements for executives"

MCE strongly supports this proposal, particularly in light of the failure to disclose material terms of executive compensation to the Commission.

As filed in the PG&E bankruptcy docket, the 2020 estimated costs of the Short-Term Incentive Plan (STIP) and Long -Term Incentive Plan (LTIP) may exceed $450 million:

> "**2020 STIP**: The total approximate cost of the 2020 STIP ranges from $0 (if the Compensation Committee and the Independent Utility Board, as applicable, determine in their discretion that no payment should be earned) to $89,000,000 at

threshold to $177,500,000 at target performance to $266,000,000 at maximum performance." [141]

"**2020 LTIP**: The aggregate value of the 2020 LTIP ranges from $0 (if the Compensation Committee and the Utility Board, as applicable, determine in their discretion that no payment should be earned) to $28,200,000 at threshold to $75,100,000 at target performance to $187,800,000 at maximum performance, all payable in equity of reorganized PG&E Corp."[142]

Further, the Declaration of John Lowe discloses that PG&E's CEO incentive compensation is solely comprised of short-term incentives. Specifically:

"Pursuant to Mr. Johnson's approved employment terms, the 2020 PG&E Corp. Performance Metrics applicable to the 2020 CEO Performance-Based Awards, however, were to be determined at a later time. The PG&E Corp. Board later determined that the 2020 CEO Performance Metrics should align with the proposed Company-Wide Weightings in the 2020 STIP, which prioritize safety by setting challenging yet achievable targets and giving public and employee safety-related metrics a 75% weighting."[143]

C. Long Term Incentive Compensation Should Be Based on Financial Health, Not Financial Performance

ACR Proposal: "Basing a significant component of long-term incentive compensation on safety performance, as measured by a relevant subset of by the Safety and Operational Metrics to be developed, as well as customer satisfaction, engagement, and welfare. The remaining portion may be based on financial performance or other considerations"

MCE recommends revising this recommendation to change the term "financial performance" to "financial health" in order to better align with the public interest rather than the shareholder interest.

[141] [Dkt. 6090] Declaration of Lowe (PG&E), at 11.

[142] [Dkt. 6090] Declaration of Lowe (PG&E), at 11.

[143] [Dkt. 6090] Declaration of Lowe (PG&E), at 15-16 (emphasis added).

D. Executive Incentive Compensation Should Be Withheld in the Event of any Material Safety Event or Any Loss of Life

ACR Proposal: "A presumption that a material portion of executive incentive compensation shall be withheld if PG&E is the ignition source of a catastrophic wildfire, unless the Commission determines that it would be inappropriate based on the conduct of the utility"

Specifically, MCE recommends that 95% of incentive payments should be tied to safety outcomes and should not be paid if PG&E causes a safety incident that results in one or more fatalities.[144] MCE recommends revising the ACR to reflect any material safety event or loss of life as follows:

> A presumption that a ~~material portion~~95% of executive incentive compensation shall be withheld if PG&E is the ignition source of a catastrophic wildfire or other material safety event occurs and that results in loss of life from PG&E conduct or omissions, unless the Commission determines that it would be inappropriate based on the conduct of the utility.

E. Recommended Addition to Proposal: Require CEO Incentive Compensation to Be Comprised of Short- and Long-Term Metrics Regarding the Financial Health and Operational Outcomes of the Utility

PG&E's current CEO Incentive Compensation is tied solely to short-term incentives. The Commission should impose requirements to ensure that incentive compensation for all employees be comprised of short-term and long-term incentives. Such incentives must be based upon the financial health and operatorial outcomes (including safety) of the utility, not shareholder-focused metrics such as earnings per share.

VI. COMMENTS ON ASSIGNED COMMISSIONER PROPOSAL #10 ENHANCED OVERSIGHT AND ENFORCEMENT PROCESS

With regard to the Commission's Enhanced Oversight and Enforcement Process, MCE recommends that the Commission:

[144] This standard is generally consistent with AB 1054, which allows for 100% of incentive compensation to be tied to a safety (fire) catastrophe resulting in one or more fatalities.

- Expanding the focus of this enforcement beyond safety to include root causes;
- Create a "Step 0" of permanent enhanced oversight to improve transparency, which would include the formation of an Oversight Committee and increased transparency requirements;
- Augment "Step 4" (Chief Restructuring Officer) to also include a Commission-appointed examiner;
- Modify "Step 5" to reflect the involvement of the Federal Courts and to ensure that a receiver is broadly empowered to consider all options, including, for example, the sale of the gas business;
- Ensure the availability of "Step 6" (Revocation of the CPCN) in the event of necessity or if other remedial steps are unfruitful.

A. Enhanced Oversight and Enforcement Must Encompass More Than Safety; Safety Is a Symptom of Other Root Causes

As MCE notes above, the Commission should expand the scope of the ACR proposals to view PG&E's safety shortcomings as a symptom of other larger challenges. This need for a broader focus is particularly true with regard to Enhanced Oversight and Enforcement processes. The Commission should expand the safety-specific Enhanced Oversight and Enforcement processes to include steps toward achieving financial health of the utility, compliance with law and ethical standards and development of a culture aligned with the public interest. Without these, PG&E is unlikely to achieve meaningful safety results.

B. The Commission Should Establish a Step 0: Permanent Enhanced Oversight to Improve Transparency and Align PG&E's Decisions with the Public Interest

MCE strongly recommends the Commission adopt a Step 0 for Enhanced Oversight and Enforcement. This step will result in increased and continued oversight of PG&E without requiring the corrective action plan needed for the other steps. This step is intended to address the ongoing challenges with aligning PG&E's decisions with the public interest. MCE proposes two distinct transparency and oversight proposals to include in Step 0 that should be adopted for PG&E immediately and indefinitely.

1. Formation of an Oversight Committee

MCE recommends improving oversight of PG&E decision making to better align with the public interest over time. MCE recommends establishing an Oversight Committee composed of independent representatives with expertise in safety, affordability, reliability, equity, and climate. This committee is inspired by the Low-Income Oversight Board that currently advises the Commission and serves as a liaison for low-income ratepayers and representatives.[145] However, this Committee differs as it would not be an agent of the Commission and would be positioned to advise the Commission, the Legislature, and the broader public.

The representatives of the Oversight Committee should include: (1) three customer representatives including a low-income customer representative, a disadvantaged communities customer representative, and an access and functional needs customer representative; (2) three local government representatives that are concurrently serving as elected officials from different communities PG&E serves; (3) an environmental representative; (4) two emergency services representatives including one from an organization with wildland firefighting expertise; and (5) one reliability representative with technical expertise in distribution and transmission grid operations. These representatives should be appointed by the Governor and will be charged with ensuring PG&E's decisions are aligned with the public interest.

[145] Originally authorized in SBX2 2 (2001).

The Oversight Committee should be endowed with special powers including: (1) review and consultation with PG&E before PG&E files any requests for additional spending; (2) presumed standing to engage as a party in any Commission proceeding where PG&E has an interest and access to intervenor compensation; (3) standing authority to issue data requests to PG&E on any issue at any time regardless of the scope of open proceedings; (4) provide annual reports to the Commission that identify inconsistencies between PG&E's decision making and the public interest; and (5) the ability to provide testimony during legislative oversight hearings of the Commission. Such an oversight board, tasked with serving the public interest, should be a permanent feature of PG&E and a best practice to consider for other investor owned utilities in California.

2. Increased Transparency

PG&E must be exposed to stronger and continued oversight following their exit from bankruptcy. One of the best forms of oversight is simple transparency. By its own existence, it steers board rooms and back offices to set aside self-interest and follow the public interest. The Commission should look to two of California's stalwart stewards of the public interest: (1) the Public Records Act and (2) the Brown Act. These laws require public organizations to make their records available for inspection and make their decisions in public. The Commission's own ability to inspect records and serve as a gatekeeper to PG&E's decision making is necessarily limited by the resources of the Commission. Expanding transparency to the broader public will increase the incentives and oversight for PG&E to act in the public interest. The Commission should apply the provisions of the Public Records Act and Brown Act to PG&E indefinitely.

C. Step 4 Appointing a Chief Restructuring Officer Should be Augmented with the Commission Appointment of an Examiner

The appointment of a Chief Restructuring Officer may be a good step to effect internal changes within a company, it will only be effective where the company is internally motivated to change. As a result, Step 4 may be improved by augmenting the authority of the monitor or including a Commission-appointed examiner with authorities greater than those of a monitor. Examiners are used in the banking context evaluate the bank's risk management systems and controls and evaluating whether the bank is operating in in a prudent manner and in compliance with laws and regulations.

Examiners in the banking industry have the power to make a thorough examination of all the affairs of a bank and its affiliates, with the power to administer oaths while examining any officers or agents of the bank, and threat of forfeiture of the bank franchise for refusal to cooperate.[146] A similar examiner is appropriate for Step 4, to proactively and independently examine the utility while the Chief Restructuring Officer is taking control of operations. These two elements are also a logical precursor to an independent receiver being appointed to take control of PG&E operations in Step 5.

D. Step 5: Appointment of a Receiver or Chapter 11 Trustee

MCE addresses certain criteria for the appointment of an examiner in Chapter 2.III. The appropriate venue is a federal court rather than a state court. MCE recommends that the receiver not be constrained by prohibitions on its ability to "dispose of the operations, assets, business or PG&E stock," as set forth in the ACR. Upon the appointment of a receiver, all options to rehabilitate the Utility should be on the table.

[146] 12 U.S. Code § 481.

E. Step 6: Review of CPCN

MCE supports Step 6 and the pathway to revocation of the Certificate of Public Convenience and Necessity (CPCN) as an appropriate option for a utility that egregiously violates the public interest. PG&E may find itself in Step 6 if it cannot correct its course soon. Defining this path and demonstrating a willingness to revoke the CPCN sends an important message and creates new incentives for PG&E to act in the public interest. The Commission is wise to clearly articulate the process required for revocation of the CPCN.

VII. MCE RECOMMENDS THAT PG&E BE PLACED IN STEP 5, APPOINTMENT OF A RECEIVER, AT THIS TIME

The Commission should exercise its authority to appoint an independent monitor while it pursues receivership for PG&E. As discussed in Chapter 2, Sections IV (Rate Neutrality) and V (Hold Co) above, the PG&E Plan requires a waiver of the normal rules for a regulated utility, places the ratepayers at great financial risk, and inappropriately extracts value from the utility to benefit the corporation. Section VI above describes why PG&E should be appointed a receiver as soon as possible, which will require court action, most appropriately in the court of Judge Alsup, at the behest of the Commission. As a result of these extensive shortcomings, and PG&E's abhorrent safety record, PG&E requires a corrective action plan and should be appointed a monitor immediately pending appointment of a receiver.

VIII. CONCLUSION

MCE thanks President Batjer and Assigned Administrative Law Judge Allen for their consideration of these important matters.

Respectfully submitted,
/s/ Elizabeth Kelly
Elizabeth M. Kelly
LAW OFFICE OF ELIZABETH KELLY
P.O. Box 225037
San Francisco, CA 94122
Telephone: (415) 535-9998
Email: beth@emk-law.com

Counsel for:
MARIN CLEAN ENERGY

March 13, 2020

Appendix A

The Revisions of PG&E's March 9, 2020 Amended Plan of Reorganization Are Examples of PG&E Providing Financial Return to Shareholders Notwithstanding PG&E's Precarious Financial Position

MCE on March 9, 2020, PG&E filed a further amended plan of reorganization.[147] The primary purpose of such amendment was to further strengthen the position of shareholders, namely:

- Ensuring that PG&E's existing shareholders are entitled to a lien on Utility property (Section 1.24);
- Releasing PG&E from environmental claims (Section 1.63), which would include environmental impacts regarding urgent shut-downs resulting from PG&E's failure to adequately communicate with commercial and industrial customers;
- Including within the capped amount for the fire victims any "HoldCo Recession or Damage Claim" (Section 1.78, Section 1.108), locking in the benefit of the Equity Backstop Agreements at the expense of fire victims, then further treating those claims as impaired to allow for PG&E shareholder voting of the plan (Section 4.14) and diluting the votes of creditors such as fire victims that are actually impaired;
- Obscuring, but not changing, the terms of "Reinstatement" to address the insolvency of PG&E, including post-bankruptcy (Section 1.178);
- Changing the definition of Utility Impaired Senior Note Documents (Section 1.228) to include other documents, such as side letters undisclosed to other parties;
- Ensuring that all "Administrative Expense Claims" are discharged on or prior to the Effective Date (Section 2.1) ensuring cash payment to Corporation shareholders;
- Allowing for all DIP Facility Claim collateral to be cancelled on the Effective Date (Section 2.3) placing the risk on PG&E;
- Allowing fees and charges to flow through the PC Bond (2008 F and 2010 E) documents to shareholders Section 4.22);

[147] A redline of this plan of reorganization dated March 9, 2020 is available at [Dkt. 6218]. MCE refers in this brief and comments to the Plan of Reorganization dated January 31, 2020. References in this subsection are to paragraph numbers of [Dkt. 6218].

- Ensuring priority disbursement to PG&E shareholders from the Disbursing Agent from the Wildfire Trust (Section 5.6), ahead of the claims of fire victims;
- Ensuring reimbursement by PG&E for the "out-of-pocket expenses, excluding any professional fees" of the PG&E shareholders up to $150,000; and
- Pushing back approval of "for awards of compensation for services rendered and reimbursement of expenses incurred" from the Confirmation Date to the Effective Date (Section 11(h)), limiting review of those expenses before confirmation of the plan.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON PROPOSED DECISION ON
2019-2020 ELECTRIC RESOURCE PORTFOLIOS TO INFORM
INTEGRATED RESOURCE PLANS AND TRANSMISSION PLANNING

Evelyn Kahl, General Counsel
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
regulatory@cal-cca.org

March 12, 2020

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page

CPUC Commission Orders and Decisions

Miscellaneous

SUBJECT INDEX OF RECOMMENDATIONS

CalCCA generally supports adoption of the proposed decision, modified as follows to:

- ✓ Clarify that LSEs must present a Conforming Portfolio for aggregation purposes but may also provide Alternative Portfolios to inform ongoing refinement and improvement to Integrated Resource Plan ("IRP") assumptions and processes.
- ✓ Acknowledge that the PD's allocation of exports from combined heat and power ("CHP") resources among LSEs is an interim solution, and limit any such allocation to the amount of CHP not otherwise shown directly in an LSE's individual plan;
- ✓ Correct the PD's characterization of CalCCA's position on import RA constraints; CalCCA proposed using a declining trendline rather than a static 11 GW constraint; and
- ✓ Prohibit reliance on new-build natural gas resources to meet procurement track requirements or, at a minimum, clarify the scope of projects that would be eligible for compliance.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PROPOSED DECISION ON 2019-2020 ELECTRIC RESOURCE PORTFOLIOS TO INFORM INTEGRATED RESOURCE PLANS AND TRANSMISSION PLANNING

The California Community Choice Association[1] (CalCCA) submits these comments on Administrative Law Judge Fitch's proposed decision addressing 2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning ("PD") issued on February 21, 2020.

I. INTRODUCTION AND SUMMARY

CalCCA appreciates the opportunity to provide comments on the PD's proposed Reference System Plan ("RSP"), which will inform individual load-serving entity ("LSE") integrated resource plans but will not be used by the California Independent System Operator ("CAISO") for purposes of transmission planning. CalCCA generally supports adoption of the PD, modified as follows to:

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, Clean Power SF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

- ✓ Clarify that LSEs must present a Conforming Portfolio for aggregation purposes but may also provide Alternative Portfolios to inform ongoing refinement and improvement to Integrated Resource Plan ("IRP") assumptions and processes.
- ✓ Acknowledge that the PD's allocation of exports from combined heat and power ("CHP") resources among LSEs is an interim solution, and limit any such allocation to the amount of CHP not otherwise shown directly in an LSE's individual plan;
- ✓ Correct the PD's characterization of CalCCA's position on import RA constraints; CalCCA proposed using a declining trendline rather than a static 11 GW constraint; and
- ✓ Prohibit reliance on new-build natural gas resources to meet procurement track requirements or, at a minimum, clarify the scope of projects that would be eligible for compliance.

Appendix A presents proposed changes to the PD's text, Findings of Fact, and Conclusions of Law.

II. THE PD'S DIRECTIVES REGARDING SUBMISSION OF CONFORMING PORTFOLIOS SHOULD BE CLARIFIED

The PD requires all LSEs to file both Standard Portfolios and Conforming Portfolios that adhere to the assumptions used to form the 2019-2020 RSP.[2] The PD eliminates the Alternative Portfolio on grounds that submission of alternatives in the 2017-2018 IRP cycle made aggregation challenging.[3] While CalCCA does not oppose the PD's conclusion or reasoning, the Commission should clarify the PD to require Conforming Portfolios *for the purpose of aggregation*, but permitting the presentation of Alternative Portfolios to inform development of the Preferred Resource Plan ("Plan") and future RSP modeling.

LSEs may find in the development of their Conforming Portfolios that the underlying assumptions do not adequately represent the LSE's circumstances. For example, an LSE may adopt a lower greenhouse gas ("GHG") benchmark for the load it serves, increase assumptions

[2] PD, Ordering Paragraph 5 at 80-81.
[3] *Id.*

regarding electric vehicle adoption, specify alternative Renewable Portfolio Standard ("RPS") constraints, or rely on different cost assumptions in response to solicitation results. In addition, some CCAs are pursuing additional sensitivity analyses that may show strong impacts from departures from RSP assumptions (*e.g.,* slower solar and storage cost declines or differences in gas price projections). Alternative Portfolios and sensitivity analyses that are presented by LSEs can help inform the adoption of a Preferred System Portfolio that accommodates variations in inputs and assumptions and is informed by actual procurement activity. This insight is particularly valuable given the proposed 2019-20 RSP had a limited number of sensitivities performed around the final set of input assumptions. It would be counterproductive to prohibit the presentation of these alternative views to Staff to inform ongoing refinements and improvements in Integrated Resource Planning ("IRP") assumptions and processes. Particularly given how quickly the energy market can change, the Commission should not foreclose the submission of new, relevant information to help guide a process that will result in real procurement decisions.

III. THE PD'S ALLOCATION OF CHP EMISSIONS SHOULD BE CLARIFIED

The PD proposes to allocate CHP resource emissions among LSEs, distinguishing between "in front of the meter" ("IFM") and "behind the meter" ("BTM") resources. While this approach may be reasonable as an interim, simplifying approach, the Commission should ensure emissions are not being misallocated or double counted.

The PD explains its CHP allocation proposal as follows:

> [E]missions from all non-dispatchable in-front-of-the-meter CHP within the CAISO is automatically allocated to each LSE according to its load share, and BTM CHP emissions will be added

> to the system total by Commission staff during the portfolio aggregation process.[4]

The PD's load-share allocation of these emissions is a result of two key assumptions: (a) the full retention of all supply-side, non-dispatchable CHP resources through the modeling horizon due to the presence of a thermal host and (b) a desire to assign these emissions to a specific LSE rather than to system power or alternately to the system total (as BTM CHP is treated).

As an initial matter, the PD does not expressly distinguish IFM from BTM CHP resources. Presumably, IFM CHP includes the export power portion of a CHP resource (which is by its very nature is BTM), while the BTM CHP includes the power produced and used by a host customer behind its utility meter. The PD should confirm its definition of these two types of CHP.

Assuming this characterization correctly reflects the PD's intent, the PD's approach is a reasonable simplification for IFM CHP, but *only* on an interim basis. The PD concludes that CHP resources are "necessary to meet existing reliability … requirements in perpetuity."[5] However, according to some stakeholders, some of these resources currently lack a contractual path for retention and therefore cannot be attributed to specific LSEs. Presumably, the PD refers to IFM CHP, since only this portion of CHP output is delivered by the grid. If the PD is correct that the IFM CHP is needed, then it is also correct that one or more of the LSEs submitting plans will ultimately procure these resources (or they will be subject to the CAISO's Capacity Procurement Mechanism ("CPM")). It is not clear, however, whether the PD also refers to BTM CHP.

---

[4] PD at 55.

[5] *Id.* at 36.

Without any further information on which LSE will procure the resource, a pro rata allocation of IFM CHP is a reasonable interim simplification. But any IFM CHP that *has already been procured* by an individual LSE should be included in the IRP plan of that LSE and deducted from the total allocated to other LSEs to ensure those emissions are being correctly attributed and not double counted.

Segregating BTM CHP emissions from an individual LSE's portfolios will support appropriate emissions accounting and decarbonization planning in several ways. First, it will clearly identify the emissions for which individual LSEs have responsibility and agency. In contrast to the IFM CHP, none of the LSEs presenting IRP plans will be procuring the BTM CHP nor will they be serving the BTM customer load. Second, it clearly identifies emissions attributable to industrial customer BTM combustion. Reducing emissions from these customers will require strategies and policies distinct from those use to address emissions from utility-scale resources, and establishing clear attribution and metrics will facilitate future policymaker intervention within the IRP and other policy venues.

IV. THE PD'S CHARACTERIZATION OF CALCCA'S POSITION ON IMPORT RA CONSTRAINTS SHOULD BE CORRECTED

The PD mischaracterizes CalCCA's position regarding modeling import RA constraints. The PD erroneously states that CalCCA supported the use of an 11 GW import constraint.[6] CalCCA recommended that, preferably, the Commission rely on a constraint trend based on a quantitative understanding of trends and events throughout the Western region, such as the timing of specific RPS requirements or the timing and magnitude of specific retirements. At a minimum, CalCCA supported a trendline approach, which is more likely to reflect the gradual tightening of the import RA market than an immediate unsubstantiated constraint. Observing

---

6 PD at 27.

market data points on import capability ranging from 6,000 MW to 11,000 MW, CalCCA concluded:

> Thus, while Staff has reasonable grounds for its caution regarding import reliance, import availability should be studied more closely to assess the pace of anticipated decline before resorting to the blunt instrument of a 5,000 MW constraint for all study years. Until a study can be completed, the Commission should modify import availability sensitivities to utilize an import constraint trendline rather than a static value.[7]

While it is too late in this IRP cycle to develop a trendline, CalCCA requests that the Commission correct the PD's characterization of CalCCA's position on import RA modeling constraints and supports the use of more granular, data-driven import assumptions in future cycles.

V. THE CAISO 2020-2021 TRANSMISSION PLANNING PROCESS SHOULD BE BASED ON THE 2019-2020 REFERENCE SYSTEM PORTFOLIO

A. The RSP Should be Updated to Enable Alignment of the CAISO Transmission Plan with the 2019-2020 RSP LSE IRP Portfolios

The PD adopts the updated 2017-2018 Preferred System Plan ("2017 PSP") as the reliability and policy-driven base case, while offering the 2019-2020 Reference System Plan adopted in this decision as a policy-driven sensitivity case.[8] Jurisdictional LSEs are required to have portfolios in their individual IRPs that conform to the 2019 RSP, even though it would be considered only as a policy-driven sensitivity in the CAISO 2020-2021 Transmission Planning Process ("TPP"). This means that both the individual LSE IRP portfolios and their aggregation will not align with the CAISO 2020-2021 transmission plan.

---

7 *California Community Choice Association Comments on Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Action*, December 17, 2019, at 20.

8 PD at 4.

This mismatch means the transmission plan to be approved by the CAISO Board of Governors will not include potential transmission upgrades needed to support the resources included in the 2019 RSP. Instead, transmission plan will be more or less consistent with the older 2017-2018 PSP that the Proposed Decision directs be forwarded to the CAISO. As a result, to the extent jurisdictional LSEs are pursuing generating projects consistent with the 2019-2020 RSP, some of those projects might not have the necessary transmission to deliver power.

CalCCA recognizes the delay in providing the RSP to the CAISO for TPP purposes and the complexity of mapping generic storage, as discussed below. These delays and complexities, however, do not justify reliance on a stale and outdated PSP. The Commission, instead, should quickly make adjustments to the 2019-2020 RSP necessary to accommodate the CAISO's reliance for purposes of the TPP. The Commission likewise should take the steps needed to ensure that a similar problem does not arise in the 2021-2022 IRP process.

B. The Commission Should Coordinate with the CAISO in Mapping Generic Storage to Specific Locations for the Sensitivity Portfolios included in the 2019-2020 RSP

The 2017-2018 PSP, which was provided as the base portfolio to the CAISO in the 2019-2020 TPP, included more than 2,000 MW of energy storage that was not mapped to specific locations, so the CAISO did not model them. Although the PD is silent about the modeling of these storage resources in the 2020-2021 TPP base portfolio, we understand that the CAISO intends to consider these resources as potential mitigation options for reliability needs identified in the 2020-2021 TPP because LSEs are expected to procure a significant amount of storage.[9]

[9] Reliability Assessment Unified Planning Assumptions & Study Plan, 2020-2021 Transmission Planning Process Stakeholder Meeting, February 28, 2019, p. 19.

CalCCA supports using energy storage as a mitigation measure without including the full capital cost as reflected in the Commission-provided base portfolio. Since the LSEs are expected to bear the cost of such procurement, when storage is considered as a candidate reliability mitigation option, it is reasonable not to consider its full capital cost while comparing it with other mitigation alternatives. CalCCA recommends, however, that the CAISO include the incremental costs[10] associated with the candidate energy storage options.

The PD indicates Commission staff will provide a full description of the methodology used to map storage to busbars in the updated version of the busbar mapping methodology to be released in March 2020.[11] CalCCA strongly supports the coordination between the CPUC staff and the CAISO in mapping generic storage to specific locations for the sensitivity portfolios included in the 2019-2020 RSP. This mapping will identify a much more significant amount of storage resources that are likely to have important impacts on the transmission system.[12]

VI. THE INTERACTION OF THE IRP PROCESS AND THE COMMISSION'S MICROGRID PROCEEDING SHOULD BE ADDRESSED

The PD implicitly raises issues related to the interaction of the IRP process with the Commission's ongoing microgrid proceeding, R.19-09-009. The PD, in rejecting the Petition for Modification filed by the California Environmental Justice Alliance, Sierra Club, Defenders of Wildlife, and CalAdvocates ("Joint PfM") to limit reliance on new fossil-fueled resources, cites the Commission's desire not to preclude "potentially desirable projects" that may rely on biomethane. [13] Presumably, this refers to proposals by Pacific Gas and Electric Company in

---

[10] One example of the incremental cost is the additional cost incurred for siting the storage in a particular local area versus locating it elsewhere.
[11] PD at 63.
[12] Policy-driven Assessment Unified Planning Assumptions & Study Plan, 2020-2021 Transmission Planning Process Stakeholder Meeting, February 28, 2019, at 16-17.
[13] PD at 69.

R.19-09-009 to undertake distributed generation-enabled microgrid services ("DGEMS") at substations, which may rely on biomethane.[14]

CalCCA agrees that there is a connection between the IRP process, particularly the Procurement Track, and the microgrid proceeding. The PD should be modified to address this connection in two respects. First, the Commission should prohibit reliance on new-build fossil resources for Procurement Track eligibility or, at a minimum, clarify the scope of acceptable projects so all LSEs are on equal footing. Second, the Commission should make clear that an IOU may not bypass the loading order or least-cost best-fit ("LCBF") justification for purposes of the IRP simply because a project is procured as a result of a plan adopted in the microgrid proceeding. Any proposed procurement of generation made to provide safe, reliable service in lieu of functioning transmission and distribution infrastructure should be compared not only with competing bids for generation, but with the costs to repair the grid.

A. The Commission Should Grant the Joint PfM or, at a Minimum, Clarify the Scope of Acceptable Projects for All LSEs

The PD addresses the Joint PfM arising from the procurement track decision, D.19-11-016. While prohibiting "new natural-gas-only resources on new sites" to meet procurement requirements, the PD left loopholes for fossil-fueled projects: "new projects that may utilize storage combined with some natural gas may be desirable,"[15] and "some augmentation of capacity, at existing sites and including efficiency improvements or repowering, may also help support system reliability." The Joint PfM requests clarification that "'the only projects that

---

[14] *See* Biomethane Request for Offers in Support of the 2019 System Reliability RFO Distributed Generation Enabled Microgrid Services ("DGEMS") Phase Solicitation Protocol https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/energy-supply/electric-fuels/rfo/Biomethane-RFO-Solicitation-Protocol.pdf.

[15] D.19-11-016 at 65.

utilize fossil fuel that may be allowed include the following narrow set of options: (1) energy storage projects that decrease GHG emissions and (2) projects that increase the efficiency or capability of existing units.'"[16]

The PD denies the PfM, in part to avoid prohibiting "potentially desirable projects such as compressed air energy storage or resiliency projects at substations utilizing biomethane."[17] CalCCA is concerned that the PD, reinforcing D.19-11-016, may lead to the development of new fossil-fueled projects to meet the Procurement Track requirements. Unless a project has enforceable provisions that it will solely use renewable natural gas as a feedstock, such projects should be assumed to be fossil-fuel resources and not counted toward procurement track resources.

An unambiguous modification of D.19-11-016, as proposed in the Joint PfM to close this loophole, would more effectively support California's climate goals. The PD takes comfort, however, in the Commission's approval process:

> Fortunately, the provisions of D.19-11-016 still require Commission consideration and approval of all the projects used by the investor-owned utilities to satisfy their obligations under the decision. Thus, if the Commission or other parties see significant problems with the procurement choices of the investor-owned utilities (IOUs), the Commission has the option not to approve those contracts for cost recovery.[18]

It further suggests that for CCAs and ESPs, "the language in the decision…serves as policy guidance."[19] Unfortunately, the "language in the decision" lacks clarity, leaving ambiguity for CCAs and ESPs whose contracts are not approved by the Commission.

---

16 PD at 66 (quoting Joint PFM at 16).
17 *Id.* at 69.
18 *Id.*
19 *Id.* at 69-70.

The Commission should grant the PfM. If the Commission denies the PfM, it must clarify the boundaries of the loophole for *all* LSEs. If the Commission rejects the Joint PfM clarifications, the Commission must more clearly articulate the types of projects it will deem acceptable for procurement track compliance to place all LSEs on a level playing field.

B. The Commission Should Require Resources Eligible for Procurement Track Counting to Conform to the Loading Order and to be Supported by a Least-Cost Best-Fit Analysis

An IOU's procurement activities are driven by the need to conform to the Commission's loading order,[20] which mandates that the IOU first consider energy efficiency and demand response to meet its needs, followed by renewable alternatives and, lastly, clean fossil generation. The IOU is also bound to perform a LCBF analysis to support its renewable procurement.[21]

The resources solicited in PG&E's "2019 System Reliability Request for Offers - Distributed Generation Enabled Microgrid Services (DGEMS) Phase" ("PG&E RFO") should not be counted toward an IOU's Procurement Track requirement *unless* PG&E's selection meets the loading order and is supported by a LCBF analysis.[22] In addition, for purposes of DGEMS projects, the Commission should consider modifying the LCBF analysis. When evaluating generation resources that serve as a replacement for transmission or distribution ("T&D") upgrades or provide reliability in areas where the T&D is unsafe to operate, IOUs seeking

---

[20] *See, e.g.,* R.16-02-007, *Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements*, February 11, 2016, at 5.

[21] *See, e.g.,* R.18-07-003, *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2019 Renewables Portfolio Standard Procurement Plans,* April 19, 2019, at 17.

[22] CalCCA observes that the Evaluation Criteria identified in Section III of PG&E's Biomethane RFO did not include these requirements. https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/energy-supply/electric-fuels/rfo/Biomethane-RFO-Solicitation-Protocol.pdf.

procurement credit for the resources must demonstrate that certain criteria are met. The generation resources they select must not only be the best among generator bids; they must also be a better lifecycle investment than grid hardening.

C. The Commission Should Consider Procurement Proposals Through an Application Process If the Objective of the Procurement Expands Beyond System Reliability Procurement

As noted above, the PD rejects the Joint PfM in large part based on grounds that the approval process of IOU procurement contracts will enable the Commission and stakeholders to address the impacts of fossil-fueled resources.[23] However, allowing the IOUs to submit this mandated procurement for approval through an advice letter process instead of an application shortens the review period to such an extent that adequate review may not be possible. As the Joint PfM points out, the Tier 3 advice letter procedure does not allow for evidentiary hearings, establishing a discovery record, or other processes inherent in an application.

CalCCA agrees with the Joint Parties. While the Tier 3 Advice Letter process may be appropriate to approve mandated procurement per D.19-11-016, it is not the appropriate venue to approve PG&E's RFO results. By proposing that mandated procurement under the IRP proceeding should also meet resiliency needs, PG&E is attempting to fit a square peg (long-term, cost-effective and reliable generation resources) into a round hole (the urgent, flexible, and short-term need for generation for resiliency purposes).

The PD also errs in concluding that "PG&E's resiliency proposals should and will be litigated in other proceedings." Only portions of PG&E's permanent generation DGEMS proposal will be litigated in R.19-09-009, *i.e.* the upgrades necessary for substations to

---

[23] PD at 69.

accommodate generation (*i.e.* the "Make Ready Program"); the actual generation resources are being solicited under IRP.

There will likely be numerous factual issues arising from PG&E's eventual proposals to the Commission. For example, mitigation responses to PSPS events must first be addressed with wire solutions, such as line hardening and sectionalization. This work, which is being implemented by PG&E over the next 10 years, will necessarily change the need for generation solutions for resiliency purposes. Therefore, any generation installed for resiliency purposes must (1) be temporary in nature and (2) must be able to adapt to changing needs for generation based on wire upgrades, changes in load at the substation, and changing wind and weather patterns. A Tier 3 advice letter is not the appropriate venue for a first-of-its-kind resiliency proposal with questionable cost-effectiveness that also includes significant greenhouse gas emissions impacts on local communities. The Commission should direct that a single proceeding address the full cost, ratepayer impacts, factual issues, and resiliency aspects of the permanent generation DGEMS proposal.

In addition, through the PG&E RFO, PG&E expands the scope, costs, and strategic impacts of the mandated procurement order. PG&E is *de facto* developing a full resiliency strategy with expansive cost, emissions, and precedent-setting impacts. This type of procurement strategy goes far beyond what was originally envisioned by the Commission when allowing mandated procurement under the IRP to be approved by a Tier 3 Advice Letter. Therefore, the appropriate venue for stakeholder review in this instance is an Application.

D. Cost Allocation for Resources Overlapping Procurement and Microgrid Purposes Must Be Clear

Projects that an IOU claims to serve two purposes – meeting system reliability requirements and providing resiliency – create ambiguity in cost responsibility. CalCCA submits that if an IOU seeks Procurement Track eligibility for a dual-purpose project, cost recovery should remain with bundled customers.

VII. CONCLUSION

CalCCA appreciates this opportunity to provide input on the PD and supports adoption of the PD subject to the recommendations presented in these comments.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

March 12, 2020

APPENDIX A

Proposed Changes

Corrections to Text at page 27

On the import assumptions, parties had mixed opinions on whether to use 5 GW as the import limit (CAC, AWEA, and CalWEA supported this level), the MIC level of 11 GW (UCS, Cal Advocates, ~~CalCCA,~~ and POC supported this level), or something else (Powerex supported a 3 GW import limit). CalCCA recommends using a constraint trend based on a quantitative understanding of trends and events throughout the Western region, such as the timing of specific RPS requirements or the timing and magnitude of specific retirements or, at a minimum, a declining trendline.

Findings of Fact

24. ~~There is too much~~ While there is geographical uncertainty associated with the capacity identified in the 2019-2020 RSP adopted in this decision, particularly with respect to battery storage, using ~~to use~~ the 2019-2020 RSP as the reliability and policy-driven base case for the CAISO TPP this year would better align transmission planning with the direction of procurement.

25. ~~Several updates and improvements to the 2017-2018 PSP are reasonable~~ Refinement of the 2019-2020 RSP is needed, include mapping storage resources, ~~if it continue~~s to be utilized for CAISO TPP purposes~~, including updates to the baseline resources, updates to the locations of some generation delivering to particular substations, and updates based on commercial interest in the CAISO interconnection queue~~.

Conclusions of Law

New. LSEs may submit, in addition to Conforming Portfolios, Alternative Portfolios to inform the development of the PSP and potential updates to the IRP process for the next cycle.

22. The Commission should utilize the 2019-2020 RSP ~~2017-2018 PSP~~ as the reliability and policy-driven base case, with updates as described in this decision, to forward to the CAISO for purposes of its 2020-21 TPP.

~~23. The Commission should forward the 2019-2020 RSP adopted in this decision to the CAISO as a policy-driven sensitivity for its 2020-21 TPP.~~

29. The December 11, 2019 PFM of CEJA, Sierra Club, DOW, and Cal Advocates of D.19-11-016 is granted ~~should be denied~~.

Ordering Paragraphs

8. For purposes of the California Independent System Operator's Transmission Planning Process for 2020-21, the Commission requests that the CAISO rely on the ~~requests the following scenarios be studied, and forwarded by Commission staff with detailed busbar mapping to the extent possible: (a) The 2017-2018 Preferred System Portfolio adopted in Decision 19-04-040, with updates to the baseline and some generation locations as detailed in this decision, as the reliability base case and the policy-driven base case.~~ (b) The 2019-2020 Reference System Portfolio adopted in this decision ~~as a policy-driven sensitivity~~.

10. The December 11, 2019 Petition for Modification of Decision 19-11-016 of the California Environmental Justice Alliance, Sierra Club, Defenders of Wildlife, and the Public Advocates' Office is granted ~~denied~~.

11. The interaction of the IRP procurement track and any DGEMS proposals must be addressed in a separate track, including cost allocation and IPR procurement track eligibility for DGEMS driven resources.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

OPENING COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION CONSIDERING WORKING GROUP PROPOSALS ON DEPARTING LOAD FORECAST AND PRESENTATION OF POWER CHARGE INDIFFERENCE ADJUSTMENT RATE ON BILLS AND TARIFFS

Evelyn Kahl
General Counsel
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, California 94521
Tel: (415) 254-5454
E-Mail: regulatory@cal-cca.org

March 17, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

OPENING COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION CONSIDERING WORKING GROUP PROPOSALS ON DEPARTING LOAD FORECAST AND PRESENTATION OF POWER CHARGE INDIFFERENCE ADJUSTMENT RATE ON BILLS AND TARIFFS

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the California Community Choice Association ("CalCCA") [1] respectfully submits these opening comments on the proposed *Decision Considering Working Group Proposals on Departing Load Forecast and Presentation of Power Charge Indifference Adjustment Rate on Bills and Tariffs* ("Proposed Decision").

The Proposed Decision reasonably and without error addresses Working Group 1 Issues 8-10 and 12. In particular, CalCCA supports the following conclusions:

- ✓ "The record provided by the July Report does not contain sufficient details for the Commission to adopt and implement a BNI process."[2]
- ✓ The investor-owned utilities ("IOUs") "shall collaborate to submit a joint proposal for bill and tariff changes to show a power charge indifference adjustment line item in their tariffs and bill summary table on all customer bills. Each utility shall submit a Tier 3 Advice Letter by August 31, 2020, to implement the joint proposal by the last business day of 2021.[3]

---

1 California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.
2 *Id.*, Finding of Fact 8 at 27.
3 *Id.*, Ordering Paragraph 2 at 29-30.

- ✓ "The Joint IOU proposal to remove the line loss factor from the calculations underlying the Power Charge Indifference Adjustment should not be adopted. The IOUs may file a petition to modify the relevant decision."[4]

While CalCCA sought more definitive progress in Working Group 1 on departing load forecasting, insufficient information was made available to design more effective forecasting methods. CalCCA thus supports the Proposed Decision's conclusion that "current utility practices of load forecasting should continue to be subject to review in respective proceedings (e.g., ERRA, RPS, RA)."

For these reasons, CalCCA supports the Commission's adoption of the Proposed Decision without modification.

Respectfully submitted,

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

Evelyn Kahl
General Counsel

March 17, 2020

---

[4] *Id.*, Conclusion of Law 9 at 29.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION CONSIDERING WORKING GROUP PROPOSALS ON DEPARTING LOAD FORECAST AND PRESENTATION OF POWER CHARGE INDIFFERENCE ADJUSTMENT RATE ON BILLS AND TARIFFS

Evelyn Kahl
General Counsel
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, California 94520
Tel: (415) 254-5454
E-Mail: regulatory@cal-cca.org

March 23, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION CONSIDERING WORKING GROUP PROPOSALS ON DEPARTING LOAD FORECAST AND PRESENTATION OF POWER CHARGE INDIFFERENCE ADJUSTMENT RATE ON BILLS AND TARIFFS

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the California Community Choice Association ("CalCCA") [1] respectfully submits these reply comments on the proposed *Decision Considering Working Group Proposals on Departing Load Forecast and Presentation of Power Charge Indifference Adjustment Rate on Bills and Tariffs* ("Proposed Decision").

I. INTRODUCTION

CalCCA supports the Commission's adoption of the Proposed Decision without modification as a reasonable resolution of Working Group 1 Issues 8-10 and 12. These comments reply to the Joint Utilities' proposal to modify the Proposed Decision's disposition of Issue 12.[2] In particular, the Joint Utilities propose to remove the requirement to implement, by the last business day of 2021, a joint proposal to show a power charge indifference adjustment

---

1 California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

2 *Opening Comments of Pacific Gas and Electric Company (U 39 E), Southern California Edison Company (U 338 E), and San Diego Gas & Electric Company (U 9002 E) on Proposed Decision on Departing Load Forecast and Presentation of Power Charge Indifference Adjustment Rate on Bills and Tariffs*, Mar. 16, 2020 ("Joint Utilities Comments"), at 3.

("PCIA") line item in the tariffs and bill summary table on all customer bills. The Commission should reject the Joint Utilities' proposal as an unsupported attempt to continue their pattern of delay on this issue.

II. THE COMMISSION SHOULD REJECT THE JOINT UTILITIES' PROPOSAL TO FURTHER DELAY IMPLEMENTATION OF A PCIA LINE ITEM ON ALL CUSTOMER BILLS

The Proposed Decision requires the Joint Utilities to submit a joint proposal for bill and tariff changes to show a PCIA adjustment line item in their tariffs and bill summary table on all customer bills.[3] It makes crystal clear when and how the Joint Utilities must proceed in meeting this requirement, providing: "Each utility shall submit a Tier 3 Advice Letter by August 31, 2020, to implement the joint proposal by the last business day of 2021." The Commission should adopt the Proposed Decision's recommendation without change, rejecting the Joint Utilities' attempt to further delay implementation of this important bill feature.

The Proposed Decision is not the Joint Utilities' first notice that a PCIA line item on bills was in their future. CalCCA proposed in its opening testimony in R.17-06-026 on April 2, 2018, "that the Commission require the Joint Utilities to present uneconomic portfolio costs as a separate line item on bundled customer bills to better align customer understanding of the rates they pay."[4] CalCCA explained the reasoning underlying this proposal:

> "[T]he current utility bill presentation masks the fact that all customers are shouldering the burden of the utility's uneconomic costs," and "without explanation, customers might erroneously conclude that CCA customers are required to pay additional costs not included in bundled service."[5]

---

3 Proposed Decision, Ordering Paragraph 2, at 29.
4 *See* D.18-10-019 at 118.
5 *Id.*

The Joint Utilities, expressing support for greater rate and bill transparency, urged the Commission not to adopt the proposal but to hold workshops "to identify the impacts of this change on existing GRC Phase 2 settlements and the Joint Utilities' tariffs and billing systems, so that a more informed and thoughtful approach can be taken …."[6] While CalCCA did not oppose a workshop process, it requested that the Commission set a deadline for implementation, which it did not.[7]

The issue of bill presentation was fully discussed during Working Group One meetings, with conclusions summarized in the Working Group One's final report. Notably, the presentation entitled "Bill Presentation: IOU Perspective," attached to the Final Report, laid out the Joint Utilities' concerns about making the change, noting Customer Information System ("CIS") "freezes" in 2020 and the backlog of billing system changes that are pending.[8] While PG&E showed long lists of priorities in 2019 and 2020, its presentation did not suggest it could not complete the task by the end of 2021.[9] SDG&E suggested that even taking into account its CIS freeze, changes to its billing system could be made after the second quarter of 2021.[10] SCE proposed to defer the change to its 2021 General Rate Case Phase 2 proceeding,[11] which should – barring all delays – be implemented effective January 1, 2021. In other words, despite their continuing protest, there was tacit agreement that there was no barrier to implementation of the PCIA line item by the end of 2021. Contrary to the Joint Utilities' contention otherwise, the

---

6 *See* Proposed Decision at 118.
7 *See id.*
8 *Pacific Gas and Electric Company (U 39-E) and California Community Choice Association Working Group One Report on Issues 8-12*, Jul 1, 2019 ("Final Report"), beginning at C-62.
9 *Id.*at C-62 – C-64.
10 *Id.* at C-66.
11 *Id.* at C-67.

record *does* "support a Finding of Fact that a PCIA line item on bills and tariffs is feasible by the end of 2021."[12]

Moreover, the Joint Utilities' complaints cannot be easily substantiated through publicly available information. PG&E claims it is "currently working through an unprecedented backlog of billing system and billing statement changes" – a backlog that is opaque to other parties. Indeed, there is no indication of whether the utility even tried to incorporate the mandated PCIA change into its plans over time. The Joint Utilities' claim that "there *may* be utility-specific technological constraints that require additional timing flexibility,"[13] without any explanation or documentation of those constraints. They further state, referencing a communication in a different proceeding, that "SCE shared with Commission decisionmakers its current anticipated timeline for implementation of its Customer Service Re-Platform project."[14] It is interesting that the Joint Utilities can claim, on one hand, that the Proposed Decision lacks a factual basis and, on the other, provide excuses for foot-dragging that are entirely outside of the record.

By the Proposed Decision's mandated implementation date, the Joint Utilities will have had *more than three years* to develop a proposal and get the implementation scheduled. But now, as they did in Phase 1 and the Phase 2 Final Report, the Joint Utilities protest any firm implementation date. The Commission should reject their pleas for further delay and adopt the Proposed Decision without modification.

---

[12] Joint Utilities Comments at 4.
[13] Joint Utilities Comments at 4.
[14] *Id.*

III. CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission adopt the Proposed Decision without change.

Respectfully submitted,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl

Evelyn Kahl
General Counsel

March 23, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE FINAL REPORT OF WORKING GROUP 3 CO-CHAIRS SOUTHERN CALIFORNIA EDISON COMPANY (U 338E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY

Evelyn Kahl
General Counsel
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, California 94521
415.254.5454
regulatory@cal-cca.org

Ann Springgate
Meghan Thomas
Buchalter, A Professional Corporation
55 Second Street, Suite 1700
San Francisco, California 94105
415.227.0900
aspringgate@buchalter.com
mthomas@buchalter.com

Counsel to the
California Community Choice Association

March 27, 2020

Contents

Table of Contents continued

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE FINAL REPORT OF WORKING GROUP 3 CO-CHAIRS SOUTHERN CALIFORNIA EDISON COMPANY (U 338E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY

Pursuant to the January 22, 2020 Administrative Law Judge's ("ALJ") Ruling Modifying Proceeding Schedule, the California Community Choice Association ("CalCCA")[1] respectfully submits these Reply Comments on the Final Report of Working Group 3 submitted by Co-Chairs CalCCA, Southern California Edison Company ("SCE"), and Commercial Energy.[2]

I. INTRODUCTION AND SUMMARY

CalCCA urges the Commission to adopt the consensus proposals put forward by the Working Group to effect a significant improvement over the status quo and a large step toward meeting the Commission's goals of optimizing Investor-Owned Utility ("IOU") portfolios and reducing costs for all customers. Interestingly, the Opening Comments received on the Final

---

1 California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

2 Final Report of Working Group 3 Co-Chairs: Southern California Edison Company (U-338E), California Community Choice Association, and Commercial Energy, February 21, 2020 ("Final Report").

Report of Working Group 3 included several proposals by various parties – disconcertingly, some of which were newly proposed, after a full year's worth of effort by the Co-Chairs to develop and socialize its proposals. These new proposals are not actionable and would not be effective to achieve the goals of this proceeding. Some, in fact, would result in many LSEs being in a less desirable position than they are now.

CalCCA therefore urges the Commission to:

- ✓ Adopt the consensus proposals instead of the alternatives proposed, which do not improve the status quo and in some cases are a step backward;
- ✓ Adopt CalCCA's proposed timeline to implement the consensus proposals as soon as possible;
- ✓ Determine the consensus proposal for long-term RPS allocation is consistent with Public Utilities Code Section 399.13(b), or clarify its interpretation of the statute;
- ✓ Make clear that IOUs' portfolio optimization efforts are subject to the PCIA rate cap established in Decision ("D.")18-10-019;
- ✓ Require the IOUs to report on their actions and inactions with respect to the RFI and solicitation processes proposed by the Co-Chairs in each IOU's ERRA application; and
- ✓ Adopt the Co-Chairs' proposal for a full allocation of Local RA to ensure an equitable distribution of the attributes of PCIA-eligible assets to the LSEs, and their customers, who helped pay for them.

II. THE ALTERNATIVE PROPOSALS DO NOT IMPROVE THE STATUS QUO AND FAIL TO ADDRESS THE QUESTIONS PHASE 2 WAS INTENDED TO RESOLVE

Decision 18-10-019 laid out the stated purposes of Phase 2 of this proceeding, which were to develop new "structures, process and rules" for portfolio management, and "minimize further accumulation of uneconomic costs."[3] As set out in the Scoping Memo, Phase 2 was established to change the status quo "in order to address excess resources in utility portfolios."[4]

---

3 D.18-10-019 at 112.

4 R.17-06-026 *Phase 2 Scoping Memo and Ruling of Assigned Commissioner*, February 1, 2019 at 5.

The alternative proposals put forward by San Diego Gas & Electric Company ("SDG&E"), Pacific Gas & Electric Company ("PG&E") and Alliance for Retail Energy Markets and Direct Access Customer Coalition ("AReM/DACC") would, at best, maintain the status quo, and are in some aspects a step backward. Indeed, AReM/DACC has put forward no specific and actionable proposal, suggesting that action be deferred to some future date and proceeding. All of these parties' comments thus fail to address the fundamental issues Phase 2 was intended to resolve.

A. SDG&E's Hybrid Allocation Framework Is a Step Backward

Under SDG&E's "Hybrid Allocation Framework" proposal, the IOUs would make "excess portfolio resources" available to market participants in the "bilateral market."[5] If, following this sale and the Commission's final determination of each LSE's obligations, there remains "unsold excess," that volume will be allocated to all LSEs on a peak load ratio basis.[6] This process would take place annually until each IOU "no longer has any excess portfolio and has effectively reduced its PCIA eligible vintaged portfolio to meet only the compliance obligations of its bundled service customers."[7]

1. The Hybrid Allocation Framework Combines the Worst Aspects of the Excess Sales Construct and PAM and Is Worse Than the Status Quo.

The proposed offer of IOUs' "excess" to the bilateral market, after retaining whatever the IOU determines it needs for its own compliance, is simply the status quo: this is exactly what happens now. Making matters worse, however, SDG&E's proposed Hybrid Allocation Framework increases the risk non-IOU LSEs face under the existing framework by increasing IOU discretion. Following the IOUs' sales in the bilateral market, the IOU would then allocate

---

5 Comments of San Diego Gas & Electric Company (U 902 E) on the Phase Two, Working Group Three Final Report, March 13, 2020 ("SDG&E Comments") at 5.

6 *Id*. at 5-6.

7 *Id*. at 6.

those "excess" volumes out to other LSEs, very late in the compliance cycle. The LSEs do not have the option to decline this allocation. In other words, each LSE will be forced to take – and pay for – attributes the IOUs have determined they don't need, regardless of the LSE's own position or needs.

As a practical matter, this is not a workable proposal. Under SDG&E's proposal, the IOUs will not decide whether to allocate volumes to LSEs until *after* LSEs have received their final compliance obligation- by which time many LSEs will have already procured their estimated obligation. Thus, LSEs will receive an allocation of an unknowable volume of attributes, and potentially find themselves in a long position, at a time when the market for such attributes will be close to non-existent. LSEs, who have no option to decline this allocation, will thus have no opportunity to monetize their new acquisitions. This will undermine Guiding Principle b. that the PCIA methodologies "should have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon."[8]

SDG&E explains this timing issue as necessary because IOUs will not know their compliance obligation, and thus, IOUs will not be able to determine their "excess," until all LSEs receive word of their final obligations. But this timing issue highlights how completely unequal treatment of IOUs and other LSEs is under the proposal. Non-IOUs bear *all* of the costs of whatever volumes the IOU determines it does not need, as noted, without any ability to plan for what that amount might be. This will be the case even if the IOU was wildly inaccurate and could have, but did not, offer these volumes for sale earlier. By giving the IOUs full discretion, with no restrictions on when they must act, SDG&E's Hybrid Allocation Model combines the worst aspect of the "Excess Sales" construct – the idea that IOU needs alone determine what is

---

[8] R.17-06-026 *Scoping Memo and Ruling of Assigned Commissioner*, September 25, 2017 at 14.

"excess" – with the Portfolio Monetization Mechanism/Green Allocation Mechanism ("PMM/GAM") that the Commission rejected in Phase 1 of this proceeding.[9]

2. The Hybrid Allocation Framework Contains No Incentives for IOUs to Reduce Their Portfolios

Because the Hybrid Allocation Framework allows the IOUs to allocate out to LSEs whatever excess remains after the IOUs' portfolio optimization efforts, the IOUs are under no incentive to increase or make those efforts more effective. This, again, proposes no changes to the status quo. This phase of the proceeding results from the Commission's determination that the IOUs must increase their portfolio optimization efforts to reduce their portfolio costs. The IOUs' efforts have so far proved ineffective in reducing the IOUs' portfolio costs, and there is nothing in the Hybrid Allocation Model to drive the change this proceeding was intended to address.

B. PG&E's Attribute Distribution Framework Is Unworkable and Contrary to Commission Decisions

PG&E urges the Commission to reject the Co-Chairs' consensus proposal for voluntary allocation and market offer ("VAMO") in PG&E's service territory and adopt its proposal, the Attribute Distribution Framework ("ADF") in its stead. In addition, PG&E proposes the Commission take the extraordinary step of creating a structure for PG&E's service territory separate from whatever is adopted elsewhere, based on what it claims is PG&E's unique circumstance.[10] PG&E also states that it "believes portfolio optimization can be achieved without the creation of new regulatory processes, new regulatory timelines, or new products."[11]

---

[9] D.18-10-019 at 95-96.

[10] Opening Comments of Pacific Gas & Electric Company (U 39 E) on the Power Charge Indifference Adjustment Phase 2, Working Group #3 Final Report, March 13, 2020 ("PG&E Comments") at 2.

[11] *Id*. at 15.

CalCCA disagrees. PG&E's proposals would create a major, unjustified shift in the current cost recovery paradigm. At the same time, the proposals fail to address the issues intended to be resolved in Phase 2.

1. The Commission Should Defer to Previous Decisions and Exclude Local RA Resources from CAM Treatment

PG&E agrees with the Co-Chairs that full allocation of Local RA is the preferred option. However, PG&E proposes to "leverage" the existing Cost Allocation Mechanism ("CAM") process to include allocation of Local RA resources that are located in local capacity areas.[12] This is reasonable, according to PG&E, because "the utility-owned generation ("UOG") resources and non-UOG resource contracts proposed for CAM allocation located in local capacity areas were intended to, and do, provide the foundation for CAISO grid reliability. . . Because all customers benefit from reliability, these resources should be widely shared, and their costs should be fairly allocated to all customers."[13]

This characterization ignores the fact that the Commission never intended for these resources to receive CAM treatment.[14] The Commission has already ruled that these resources are subject to cost recovery through rates charged to PG&E's customers on a vintage basis. Applying CAM treatment to these resources would require all ratepayers, not just customers the Commission previously deemed responsible based on their vintage, to bear cost responsibility for these resources. In addition, the effect would be to give these resources a new, current "vintage," thereby making every ratepayer in the state responsible for their costs, regardless of whether

---

12 *Id*. at 17.

13 *Id*. at 18.

14 *See* D.06-07-029 at 25 (CAM was intended to remove many of the remaining risks or barriers, perceived or real, to investment in new generation); *id.* at 29 (Commission would not "allow utility-owned generation to qualify for this cost-benefit allocation mechanism.").

such ratepayers ever received service from PG&E, or if they did, the date they departed PG&E service.

PG&E thus proposes a seismic shift in ratemaking. PG&E justifies this shift by a few sentences regarding reliability. Ironically, in its comments PG&E argues against adoption of the Co-Chairs' allocation proposal because "such a significant and unprecedented market, regulatory, and planning transformation . . . must be carefully examined."[15] CalCCA agrees, and notes that Working Group 3 held four workshops over the last year to create a dialogue among parties and to vet the Working Group's proposals. PG&E had ample time to bring this proposal forward, yet chose not to do so.

CalCCA urges the Commission not to adopt the proposal PG&E just put forward to shift the cost recovery paradigm for Local RA. Instead of making an abrupt and unjustifiable change in the cost recovery paradigm, the Commission should defer to its earlier decisions and reject this proposal.

2. PG&E's RPS Proposal Is Only a Bandage on a Broken System

PG&E also proposes a one-time, voluntary allocation of RPS energy from its portfolio, followed by a sale of volumes in excess of what it needs for its bundled customer compliance.[16] PG&E touts this allocation as a significant reduction in "planning challenges" that would result from the VAMO process, and claims LSEs will have greater certainty from a planning perspective. PG&E also claims this approach is preferred because it has concerns regarding the design of the market offer process.[17]

---

15 PG&E Comments at 2.

16 *Id*. at 20.

17 *Id*. at 21.

The fallacy of these positions is that following this one time allocation, which would be subject to strict parameters, PG&E's proposal is simply to do what it has been doing all along. In addition, the proposal is based on an "excess sales" construct (in which PG&E alone is responsible for determining the excess) that has so far failed to reduce the IOUs' portfolios. Thus, if adopted, this proposal would not result in any change to the status quo, notwithstanding years' worth of litigation specifically addressing this subject.

3. Bundling GHG-free and GHG-emitting Resources in an Allocation Stymies Choice and Removes Value

The Co-Chairs devoted significant time to creating a structure for allocation of GHG-free attributes that would optimize the value of those attributes for all LSEs. A major aspect of this proposal is the emphasis on LSE choice. PG&E claims its proposal for GHG-free energy and attributes is "voluntary." However, the details of PG&E's proposal include aspects that effectively remove LSEs' choice from the decision.

The Co-Chairs proposed two pools of GHG-free attributes, a nuclear and non-nuclear pool, to allow LSEs that are prohibited from accepting nuclear energy to realize the value of the other GHG-free attributes in the IOUs' portfolios. PG&E's proposal does not separate nuclear from non-nuclear resources, and goes one step further. The proposal allows an LSE to take an allocation of GHG-free attributes only if the GHG-free attribute is bundled with GHG-emitting resources for the purposes of calculating the Power Content Label ("PCL") and for IRP reporting.[18] As a result, many LSEs will be prevented from accepting this allocation at all, including those LSEs whose governing documents prohibit acceptance of nuclear energy. For many other LSEs, presumably a majority, the allocation will be extremely unattractive.

---

18 *Id*. at 22.

On December 2, 2019, PG&E filed Advice Letter 5705-E, seeking approval to update its Bundled Procurement Plan to permit PG&E to allocate carbon-free energy to LSEs in 2019 and 2020 as an interim measure until Phase 2 of this proceeding is completed. The Commission posted a Draft Resolution on March 25, 2020 that would approve these updates.[19] PG&E's plan, which is quite similar to the Co-Chairs' consensus proposal, is to divide PG&E's carbon-free resources into two pools, one of large hydroelectric resources, and one of nuclear resources.[20] An eligible LSE would be able to accept an allocation share based on its proportional share of forecasted monthly load *from one or both of the resource pools*.[21] PG&E explained its request as a reasonable method for LSEs to report generation on their PCL "based on how energy from PCIA resources is actually delivered to customers."[22] Thus, in December PG&E recognized the value of GHG-free energy to LSEs, and the need to transfer that value to LSEs. PG&E also recognized the importance of segregating nuclear and non-nuclear resources.

PG&E's new proposal, in which nuclear and non-nuclear resources are bundled together and allocated only if GHG-emitting energy is taken as well, directly contradicts its own previous position. PG&E offers no explanation for its change of course. Nothing has changed in PG&E's delivery of energy since the filing of its Advice Letter. In fact, no logical connection exists that would require an LSE who accepts hydroelectric energy or nuclear energy to also be forced to accept GHG-emitting energy. Furthermore, the Co-Chairs' consensus proposal specifically addresses PG&E's most likely concern, namely, that bundled customer under the current construct bear the full emissions from emitting resources. The Co-Chairs propose to address this by changing the PCL accounting rules so the IOUs only count their proportionate share of

19 Draft Resolution E-5046, posted March 25, 2020.
20 PG&E Advice Letter 5705-E, December 2, 2019 at 2.
21 *Id*. at 3.
22 *Id*. at 4.

emissions from GHG-emitting resources. Given this proposed treatment, PG&E's proposal is rendered completely unnecessary, in addition to being unfair and illogical. CalCCA therefore urges the Commission to reject PG&E's new proposal.

By making the GHG-free allocation unacceptable to many LSEs under their foundational documents, and completely unattractive to most LSEs, PG&E's proposal will result in little to no allocation of valuable GHG-free energy. The value of that energy will thus remain in the IOUs' portfolios. Thus, there will be no change in the status quo, and Working Group 3's efforts will have all been in vain.

C. AReM/DACC and SDG&E Mistakenly Suggest the Consensus Proposal Is Out of Scope

AReM/DACC contend that the Co-Chairs have "missed an opportunity to offer a more meaningful solution" and "strayed from the Commission's direction" provided in D.18-10-019.[23] AReM/DACC claim that instead of pursuing "market-based solutions," as directed in D.18-10-019, the Working Group "has resurrected the discredited and rejected mandatory allocation scheme."[24] SDG&E also argues the Co-Chairs' consensus proposals are out of scope.[25]

CalCCA disagrees. In D.18-10-019 the Commission stated the second phase of the proceeding "should be opened in order to pursue *solutions* to the challenges of portfolio optimization and cost reductions, which will provide an ongoing opportunity to propose additional means of fulfilling [the] guiding principal."[26] Decision 18-10-019 intended the working groups to develop proposals for those solutions, and notes that the proposals should

---

23 Alliance for Retail Energy Markets and Direct Access Customer Coalition Comments on Final Report of Working Group #3 Co-Chairs, March 13, 2020 ("AReM/DACC Comments") at 1.

24 *Id*. at 7.

25 SDG&E Comments at 4.

26 D.18-10-019 at 128 *(emphasis added)*.

include "voluntary auction frameworks." [27] But nowhere in the Decision does the Commission *require* that all attributes in the IOUs' portfolios be subject to a "voluntary auction framework" or, indeed, define what that term means. Likewise, the February 1, 2019 Scoping Memo for Phase 2 ("Scoping Memo") states that it will "primarily rely on the working group process to further develop a number of PCIA-related proposals."[28] The Scoping Memo in no way limits the types of proposal to be developed, or requires parties to develop a voluntary-only structure.

CalCCA also disagrees with SDG&E's interpretation of the term "excess." SDG&E claims that Working Group 3 was intended by the Commission to deal only with those IOU assets that are "excess" to the IOUs' needs to serve bundled load.[29] But the Co-Chairs interpret the term "excess" differently. The Co-Chairs' proposals are based on their recognition that "excess" is correctly interpreted as *"excess to the bundled customers' share of the portfolio to which they are reasonably entitled*." The Co-Chairs crafted proposals that distribute out of the IOUs' portfolios resources that are excess to the IOUs' bundled customers' shares.

CalCCA, along with the other Co-Chairs and members of the Working Group, put considerable effort and thought into crafting solutions in response to the Commission's directives. The Co-Chairs' consensus proposals, including the allocation of Local RA, the VAMO construct for System and Flex RA and RPS, and a voluntary allocation for GHG-free energy, are clearly consistent with the Commission's intent.

---

[27] D.18-10-019 at 111.

[28] R.17-06-026 *Phase 2 Scoping Memo and Ruling of Assigned Commissioner*, February 1, 2019 at 3.

[29] SDG&E Comments at 3.

D. AReM/DACC Propose Only Further Delay and Fail to Recognize the Work of Working Group 3

AReM/DACC are dissatisfied with the solution crafted by Working Group 3. But AReM/DACC's comments, to the extent they can be deemed an actual "proposal," do not propose a change to the status quo, and would only defer action on the very items Working Group 3 was intended to resolve. This proceeding has been underway for almost three years and the issues it aims to address have been occurring even longer. AReM/DACC have had sufficient time to craft an actual proposal that would make specific and discrete improvements to the status quo. Further, AReM/DACC seem to ignore the actionable proposals put forward by the Co-Chairs.

1. AReM/DACC Do Not Put Forward an Actionable Proposal and Seek Only Further Delay

Instead of providing meaningful suggestions and improvements, AReM/DDACC find issues with both an excess sales approach and a mandatory allocation approach.[30] AReM/DACC therefore propose only that the Commission require the IOUs to auction off "excess" RA, RPS and GHG emission free attributes, and then redirect the Working Group (or form a new one) to "develop a more focused and concrete structure for divestiture of excess IOU resources no longer needed to serve their load."[31] AReM/DACC do not describe how to define this "excess." Requiring "excess sales" without first defining "excess" leaves each IOU with the autonomy to define it for themselves, just as they currently do. Thus, even if this proposal were actionable, it would result in no change to the status quo. Additionally, AReM/DACC make no effort to identify or address the many challenging issues that would arise from any portfolio divestiture

---

30 AReM/DACC Comments at 2-3.
31 AReM/DACC Comments at 3.

process. AReM/DACC simply have not put forward substantive proposals that could be acted upon.

2. Contrary to AReM/DACC's Statements, Working Group 3 Has Already Created "Divestiture Strategies" for IOU Assets

AReM/DACC complain that Working Group 3 focused its efforts on the allocation of various assets, instead of on "active management" to "right size" the IOUs' portfolios.[32] AReM/DACC claim there must be a "protocol" established for "divesting excess resources."[33] CalCCA argues this is precisely what the consensus proposals achieve.

CalCCA disagrees with AReM/DACC that "allocations of attributes do little to actually manage the IOUs' portfolios in line with the amount of load they are serving."[34] The Final Report of Working Group 3 includes painstaking detail on proposals to divest IOU portfolios of Local RA, System and Flex RA, RPS Energy and GHG-free energy and attributes. The Report highlights the diligent efforts of the Working Group over the past year to create these detailed proposals. In that process, the Co-Chairs concluded in particular that the kind of forced divestiture that AReM/DACC appear to propose would be extremely difficult to achieve while honoring Guiding Principle k., which states that the process "should respect the terms of existing PPAs between power suppliers and IOUs,"[35] because divesting resources (rather than attributes) requires agreement by generators for any assignment to occur.

CalCCA believes the resulting proposals constitute a "thorough structure" for distributing IOU resources, as required by the Decision and Scoping Memo. In addition, CalCCA believes that the consensus proposals for the IOUs to hold RFIs and solicit their counterparties for

---

32 *Id*. at 2.
33 *Id*. at 15.
34 *Id*. at 15.
35 D.18-10-019 at 129.

contract assignments and/or modifications addresses portfolio optimization as aggressively as is possible without abrogating existing contracts.

CalCCA therefore urges the Commission to adopt the consensus proposals and the clarifications and additional proposals put forward by CalCCA in its opening comments.

III. ALLOCATIONS SHOULD BE IMPLEMENTED AS SOON AS POSSIBLE, FOLLOWING CALCCA'S TIMELINE

Several parties advocate delaying implementation of the allocation process. SCE opposes interim allocations and states that 2022 is the earliest a solution can be implemented.[36] The Public Advocates Office argues that implementation should not occur until the IOUs determine they have had sufficient time to plan and become compliant, and so therefore supports the longer implementation process that SCE proposes.[37] PG&E advocates the creation of a separate implementation phase.[38] These positions are in direct opposition to a guiding principle in this proceeding that the solutions "have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon."[39]

A fundamental goal of this proceeding is to minimize "future accumulation" of uneconomic costs. [40] One simple method for doing so is to implement the consensus proposals as soon as possible. In addition, the utilities have themselves advocated that solutions should be implemented in the near-term, and have cautioned that any further delay will make a timely resolution of this proceeding impossible.[41] Because the IOUs presumably know their own

---

36 Southern California Edison Company's Opening Comments on the Working Group 2 Final Report, March 13, 2020 ("SCE Comments") at 8.

37 Public Advocates Office's Comments on the Final Report of Working Group 3 Co-Chairs: Southern California Edison Company (U-338 E), California Community Choice Association, and Commercial Energy, March 13, 2020 ("Public Advocates Comments") at 1-2.

38 PG&E Comments at 2.

39 Guiding Principal b., D.18-10-019 at 127.

40 *Id*. at 112.

41 R.17-06-026 *Amended Scoping Memo and Ruling of Assigned Commissioner*, March 2, 2018 at 5.

portfolios, their argument for more time to determine their needs is disingenuous. CalCCA urges the Commission adopt its proposal for interim allocation on the schedule put forward by CalCCA in the Final Report. The allocation of GHG-free and RPS attributes can take place almost immediately following a final decision in this proceeding, and System and Flex RA can be allocated beginning in 2021 for the 2022 compliance year, with Local RA allocated in 2021 for the 2023 and 2024 compliance years.

A. Coordination with Other Proceedings Can Take Place During Interim Allocation Phase, or Via Commission Direction

PG&E and Public Advocates urge careful coordination with existing regulatory processes.[42] American Wind Association California Caucus ("AWEA CA") is "largely supportive" of the Working Group 3 proposals, but notes that "there will be a need to coordinate with the RPS and IRP proceedings."[43] CalCCA agrees that coordination with the IRP and Resource Adequacy proceeding should occur, but does not believe that this coordination effort should delay the interim allocation.

AWEA CA's concerns that the implications of redistributed long-term contracts be fully evaluated in IRP and RPS filings can be resolved in those proceedings; there is no need to delay the implementation of the Co-Chairs' proposals. In addition, the IRP is designed to be an iterative process, and the allocations and sales proposed by the Co-Chairs will be reflected in the IRP as those allocations and sales take place. CalCCA proposed a detailed interim allocation schedule in the Final Report[44] because any delay in implementation ultimately deprives customers of the benefits of attributes for which they have already paid. Further, equitably

---

42 PG&E Comments at 2; Public Advocates Comments at 1.

43 Opening Comments of the American Wind Association California Caucus, March 13, 2020 at 2.

44 Final Report at 62.

distributing the RA benefits that all customers help pay for is particularly time-sensitive now, given the tightening RA market.

Under this proposal the IOUs would amend their RPS Procurement Plans via motions to update and RPS allocations could begin in 2021. CalCCA and Commercial Energy also proposed that allocations of RA begin in 2021, with the IOUs determining each LSE's allocation amount based on the preliminary RA obligations issued in July, and forecast volumes agreed by the LSEs and IOUs.[45]

Given the importance of this proceeding and in "right sizing" the IOUs' portfolios that is at the heart of the Co-Chairs' proposals, it is simply unnecessary to delay implementation of the Co-Chairs' proposals for another two years.

B. There is No Reason to Coordinate Implementation of the Allocation Proposals with Either Working Group 1 or Working Group 2

Neither Working Group 1 nor Working Group 2 require any coordination with the proposed timeline for implementing the Co-Chairs' proposals. Working Group 1 proposals have already been implemented or will be implemented soon, and any pending issues are unrelated. Similarly, Working Group 2 addresses issues unrelated to the proposals of Working Group 3.

The recommendations from Working Group 1 related to benchmarking, Questions 1-7 and 11, have already been implemented pursuant to D.19-10-001.[46] These proposals were implemented in the Commission's decisions in the IOUs' Energy Resource Recovery Account 2020 Forecast proceedings. A proposed decision is pending directing implementation of proposals arising from Working Group 1, Questions 8-10 and 12, addressing departing load

45 Final Report at 62.
46 D.19-10-001, Ordering Paragraph 4 at 56; *see also, id.*, Ordering Paragraph 6 at 57.

forecasting issues. None of these issues, however, bears on allocation of whatever portfolio resources remain.

Tying Working Group 3 resolution to adoption of a prepayment option in Working Group 2 is even more attenuated. As an initial matter, there are no definitive, detailed proposals advanced in the Working Group 2 final report.[47] At best, the proposal is a series of high-level guiding principles and evaluation criteria.[48] More importantly, the adoption of a prepayment framework will have no influence on the allocation proposals offered by Working Group 3 Co-Chairs. Prepayment options, if adopted, are simply accounting methods for dealing with revenues received from LSEs to cover above-market costs. Their effect on PCIA calculation will have to be addressed whether or not the Commission adopts the Working Group 3 proposals. Moreover, the allocation and sales frameworks can be undertaken whether or not a particular LSE chooses to exit its obligation through prepayment. The pending high-level proposals do not contemplate any change in the composition of the underlying IOU portfolios.

IV. THE COMMISSION SHOULD INTERPRET LONG-TERM RPS ALLOCATION AS PROPOSED AS CONSISTENT WITH THE STATUTE.

The Utility Reform Network ("TURN") takes issue with the consensus proposal that an LSE be permitted to receive long-term contract credit regardless of whether there are any contracts with a forward duration of a least 10 years remaining in the relevant vintage's portfolio, and contends that it violates Public Utilities Code Section 399.13(b).[49] TURN goes on to urge the Commission to find that any IOU pre-existing long-term contract does not retain its

---

47 Final Report for Working Group 2 (Prepayment) Submitted by San Diego Gas & Electric Company and the Direct Access Customer Coalition and the Alliance for Retail Energy Markets ("Final WG 2 Report").

48 *See id*., Appendix A at ii-vii.

49 Comments of the Utility Reform Network on the Final Report of Working Group #3 Co Chairs, March 13, 2020 ("TURN Comments") at 2.

compliance value under PUC Code 399.13(b) if is it subsequently allocated or resold for a term of less than 10 years.[50]

The Co-Chairs' consensus proposal for the *allocation* of RPS energy to LSEs permitting the "grandfathering" of contracts that were originally for a term of longer than ten years does not violate the statute. An allocation is not a "sale."

A. Allocation Is Not a "Sale"

As TURN describes, the Commission has previously ruled on the question of whether a long-term contract can be repackaged, with portions resold to a subsequent buyer who makes a commitment of less than 10 years.[51] The consensus proposal, however, does not require the "slicing and dicing" of existing long-term contracts that was the focus of previous Commission decisions. Rather, the consensus would merely allocate to early vintages their proportional share of RPS energy. The recipient LSEs will have no contact with the original "retail seller" and the contract itself will be untouched, including its term.

The Co-Chairs intend that early vintages, which included contracts of at least 10 years in duration that may no longer have 10 years left to run, be entitled to long-term treatment enjoyed by the IOU allocating that resource to LSEs under the proposal. The statute should not stand as an obstacle to the Co-Chairs' proposal when the original contracts remain in place, and there has been no change to the underlying contract's counterparties. Rather, the intent of the proposal is to transfer the benefit to the vintages, and therefore customers, who paid for those contracts.

CalCCA therefore respectfully requests the Commission agree with the Co-Chairs that vintages allocated contracts with less than 10 years remaining that originally had terms of at least 10 years are entitled to long-term treatment for that allocation. If the Commission determines to

---

50 *Id* at 3.
51 *Id.* at 2.

the contrary, CalCCA also respectfully requests the Commission set out its interpretation in this proceeding.

B. TURN's Proposed Solution Is Unworkable and Contrary to the PCIA Framework

As a potential solution to the issues it raises, TURN proposes that an LSE that is otherwise unable to claim long-term treatment for its allocation be permitted to "update" its PCIA vintage to the first year of the portfolio allocation.[52] According to TURN, "[u]nder this approach, the LSE would be allowed to accept a full assignment of costs and benefits associated with the entire IOU portfolio for the updated PCIA vintage."[53]

This solution is hardly a solution, and only raises more questions. TURN provides no detail about how or when these elections would occur. More significantly, changing a vintage changes the entire cost recovery framework. The basis of the entire PCIA structure is that each LSE's customers should be responsible for their share of the costs of resources from which those customers benefited, and not of resources procured after those customers departed IOU service. This is accomplished, in part, by the creation of "vintages" and the Portfolio Allocation Balancing Account accounting structure to track the costs of resources through to the appropriate customers. TURN's proposed "solution" to allow LSEs to "update" their vintages runs contrary to the entire PCIA ratemaking philosophy and structure. LSEs would become responsible for resources procured by IOUs long after the LSE's customers had departed IOU service and customers who were already standing to benefit from the resources in that vintage would have their shares reduced. CalCCA urges the Commission to reject this proposal, which would frustrate the basic purpose of the PCIA.

52 *Id.*
53 *Id.* at 3.

V. PORTFOLIO OPTIMIZATION EFFORTS SHOULD BE SUBJECT TO THE PCIA RATE CAP

As TURN notes, the Co-Chairs did not reach consensus with respect to whether costs resulting from Commission-approved contract assignments or modifications should be subject to the 0.5 cents/kWh rate cap on the PCIA adopted in D.18-10-019.[54] TURN urges the Commission find that these costs are outside the cap "if they result from actions demonstrated to result in overall customer savings in future years."[55]

CalCCA disagrees. The IOUs have consistently stressed the diligent efforts they have taken and continue to take to optimize their portfolios.[56] As they have continually explained, these efforts are part of their regular operations. These costs are therefore intended to be factored into an IOU's existing rate structure and are not exempted from the cap. The Co-Chairs' consensus proposal that the IOUs undertake targeted solicitations for contract assignments and modifications should not change the basic calculus.

The Commission has emphasized the importance of stability in the PCIA. Responding to concerns raised by the CCAs that price volatility in the PCIA added challenges to resource planning, the Commission found "the dismissal of those concerns by the Joint Utilities or Commercial Energy [to be] unpersuasive."[57] Indeed, at that time TURN argued for a cap on the PCIA rate because "[t]he potential for significant annual fluctuations in the PCIA charges can complicate individual LSE planning efforts by creating cost uncertainty that may limit their

---

[54] *Id.* at 5.

[55] *Id.*

[56] *See* Opening Brief of Pacific Gas and Electric Company (U 39-E), Southern California Edison Company (U 338-E) and San Diego Gas and Electric Company (U 902-E) on Track 2 Issues, June 1, 2018 at 63, *citing* Ex. IOU-1, pp. 3-1 to 3-4 (describing regulatory and commercial actions taken by IOUs to reduce generation portfolios); *see also* Final Report, Appendix D- Presentation of PCIA Phase 2- Working Group Three, Workshop No. 4, December 11, 2019, at slide 23.

[57] D.18-10-019 at 86.

ability to procure over longer time horizons and thereby frustrate clean resource development objectives."[58]

CalCCA agrees with TURN's previous comments, and urges the Commission to defer to the original intent of the PCIA rate cap: to protect against volatility in the PCIA.[59] An exception from the cap is inappropriate for contract assignments and/or modifications, which the IOUs should in any case be pursuing even without adoption of the Co-Chairs' consensus proposal.

VI. IOUS SHOULD BE SUBJECT TO REPORTING REQUIREMENTS FOR RFI PROCESS, AND THE ERRA PROCESS IS THE APPROPRIATE VENUE

The Co-Chairs reached consensus that IOUs should report out on their progress with the RFI and solicitation processes proposed. The Co-Chairs agreed that each IOU should report on "its implementation of the newly proposed RFI process . . . and outcomes thereof, including identification of rejected offers and the bases for rejection.[60] The Co-Chairs also reached consensus that the IOUs report in the annual ERRA Review of Operations application:

> (1) material events of defaults and any termination rights and any actions taken with respect thereto in a single section consistently formatted in each IOU's filings; and (2) cost savings received from active portfolio management.[61]
> The only substantive disagreement is with respect to the venue for these reports

SCE proposes this information be reported in a "PCIA OIR" or separate application, but in any event, not the ERRA application.[62] SDG&E argues that existing reporting is sufficient, and that no further reporting is required.[63]

---

58 *Id*. at 83, *citing* Opening Brief of The Utility Reform Network on Track 2 Issues, June 1 2018 at 33.
59 *Id*. at 85.
60 Final Report at 64.
61 *Id*.
62 SCE Comments at 15.
63 SDG&E Comments at 26.

As detailed in its Opening Comments, CalCCA urges the Commission to apply a prudent manager standard to the IOUs' actions *and inactions* with respect to the RFI and solicitation processes.[64] As recognized in D.18-10-019, "[u]tilities are of course required to manage their portfolios prudently. Imprudent management would justify disallowing recovery of portfolio costs, and could be considered in ERRA or General Rate Case (GRC) proceedings."[65] The Commission also notes that "ERRA proceedings routinely consider prudent management, including Standard of Conduct 4, which states 'utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner.'"[66]

The ERRA process is already well-established, with recognized, set standards and requirements. The information proposed to be reported could easily be added to the existing information required in ERRA applications, and there would be no need for the creation of a new process. More significantly, the information proposed to be reported here on IOUs' portfolio optimization efforts goes to the heart of the issues Working Group 3 was designed to address. It is precisely these portfolio optimization efforts that should be subject to scrutiny. The ERRA application process allows parties to propound discovery to increase transparency and stakeholder involvement. The items the Co-Chairs have agreed should be the subject of IOU reports are the very issues that should be subject to discovery. The ERRA application process is therefore the logical venue for these reports.

---

64 Opening Comments of California Community Choice Association on the Final Report of Working Group 3 Co Chairs Southern California Edison Company (U 338E), California Community Choice Association, and Commercial Energy, March 13, 2020 ("CalCCA Comments") at 10-13.

65 D.18-10-019 at 112.

66 *Id.*, *citing* D.02-10-062 at 52.

VII. FULL ALLOCATION OF LOCAL RA IS PREFERABLE TO A VOLUNTARY ALLOCATION AS IT ENSURES EQUITABLE DISTRIBUTION

The Co-Chairs' consensus proposal for Local RA is a mandatory allocation of the IOUs' portfolios, based on peak load share. The proposal is the result of months of discussion and debate concerning the pros and cons of various mechanisms for reducing IOU portfolio costs, including the "excess sales" approaches, and constructs involving voluntary allocation. As detailed in the Final Report [67] and in CalCCA's Opening Comments,[68] the Co-Chairs spent months debating these issues and ultimately rejected both of those approaches.

Shell Energy opposes the mandatory allocation framework and proposes a voluntary allocation followed by a market offer process for all RA attributes. Shell argues that the Co-Chairs' proposal does not include a financial incentive for the IOUs to divest themselves of these attributes.[69] Protect Our Communities Foundation ("POC") also argues for a voluntary allocation, followed by an auction of declined attributes. According to POC, "[b]y including a market offer for local RA the Commission can promote a liquid market and reduce ratepayers' PCIA burden."[70] AReM/DACC argue that any mandatory allocation also goes against the explicit instructions of D.18-10-019.[71]

CalCCA disagrees. In a mandatory allocation construct there is no need to craft "financial incentives." Nor is it clear that a voluntary allocation would provide any greater incentives. In addition, D.18-10-019 intended the working groups to develop proposals, and

---

[67] Final Report at 13-15.

[68] CalCCA Comments at 1-2.

[69] Comments of Shell Energy North America on the Phase Two, Working Group Three Final Report, March 13, 2020 ("Shell Comments") at 2.

[70] Comments of Protect Our Communities Foundation on the Phase Two, Working Group Three Final Report, March 13, 2020 ("POC Comments") at 2.

[71] AReM/DACC Comments at 2

noted that the proposals should include "voluntary auction frameworks." [72] The Commission could have, but did not, specify which attributes, if any, were required to be subject to voluntary allocation. The Co-Chairs' consensus proposal includes the VAMO construct for System and Flex RA, RPS, and a voluntary allocation for GHG-free energy. This is clearly consistent with the Decision's intent.

Further, as discussed in the Final Report, a mandatory allocation of Local RA based on load share resolves difficulties of determining what constitutes "excess" Local RA, and whether or not the IOU should be allowed a "buffer" or "uncertainty tranche." [73] These difficulties will be encountered with any proposed solution that does not definitely allocate all Local RA.

Presumably for these reasons PG&E's ADF proposal (which is problematic for other reasons, as discussed above) includes a mandatory allocation of Local RA. CalCCA agrees that a mandatory allocation is the optimal means to distribute Local RA equitably among LSEs.

VIII. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

/s/ Ann Springgate

Ann Springgate
Counsel to the
California Community Choice Association

March 27, 2020

---

72 D.18-10-019 at 111.
73 Final Report at 15.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization	Rulemaking 19-01-011 (Filed January 31, 2019)

REPLY COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION ESTABLISHING BUILDING DECARBONIZATION PILOTS

Michael Callahan
Senior Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
(415) 464-6045
mcallahan@mceCleanEnergy.org

March 9, 2020

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization	Rulemaking 19-01-011 (Filed January 31, 2019)

REPLY COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION ESTABLISHING BUILDING DECARBONIZATION PILOTS

Pursuant to Rule 14.3 of the California Public Utility Commission's ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE") respectfully submits the following reply comments on the *Proposed Decision Establishing Building Decarbonization Pilot Programs* filed on February 12, 2020 in this proceeding ("Proposed Decision").

MCE, California's first community choice aggregator ("CCA"), is a not-for-profit public agency that began service in 2010 with the goals of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs. MCE is a load-serving entity serving approximately 1,000 MW peak load, providing electricity generation services to more than 1.1 million people in 34 communities across four Bay Area counties.

I. INTRODUCTION

MCE supports Senate Bill ("SB") 1477 and the Commission's efforts to drive market transformation in decarbonization and electrification technologies. MCE is currently administering decarbonization programs that focus on electrification. These programs include the Low-Income Families and Tenants ("LIFT") Pilot Program that removes barriers to electrification for income-qualified multifamily tenants and supplies qualifying properties with low-cost to no-cost heat pumps, both for space conditioning and water heating. MCE's Advanced Energy Rebuild Napa Program serves residents who lost homes in the 2017 and 2018 wildfires and provides incentives for a number of electrification measures, including heat pump water heaters, heat pump space conditioning, heat pump clothes dryers, and electric induction cooktops. Both of these programs offer technical assistance and incentives to enable these communities to prioritize decarbonization through electrification. MCE's reply comments focus on the following topics:

1. The Commission should address the global warming potential ("GWP") of refrigerants, but should not impose a GWP limit on technologies at this time;
2. The Commission should support low-income and equity interests through the solicitation for the Technology and Equipment for Clean Heating ("TECH") Initiative; and
3. The Commission should encourage integration of the decarbonization pilots with other energy programs and elimination of barriers to integration.

II. THE COMMISSION SHOULD ADDRESS THE GWP OF REFRIGERANTS BUT NOT IMPOSE A LIMIT AT THIS TIME

MCE supports the comments of many parties that oppose a GWP limit for technologies under the Building Initiative for Low-Emissions Development ("BUILD") and TECH pilots.[1] MCE agrees that establishing the 750 GWP limit for BUILD and TECH would inappropriately limit the available technologies for the pilots. Such a limit would frustrate the primary purpose of

[1] California Environmental Justice Alliance, Natural Resources Defense Council, and Sierra Club Opening Comments ("CEJA-NRDC-SC Comments") at p. 1-2; California Building Industry Association Opening Comments ("CBIA Comments") at p. 1-2; East Bay Community Energy Opening Comments ("EBCE Comments") at p. 1-2; Bay Area Regional Energy Network ("BayREN") at p. 2; Sacramento Municipal Utility District Opening Comments ("SMUD Comments") at p. 3; Rheem Manufacturing Company Opening Comments ("Rheem Comments") at p.3; Vermont Energy Investment Corporation Opening Comments ("VEIC Comments") at p. 3; A.O. Smith Corporation Opening Comments ("A.O. Smith Comments") at p. 3-5.

these programs to drive market transformation for low-emissions heating and cooling technologies because new products would need to be developed before they could be incorporated into the pilots. The GWP limit may have the unintended consequence of choosing a winner, the single available water heater referenced in opening comments.[2] Such a result would also eliminate the important near-term opportunity to deploy heat pump water heaters in low-income multifamily properties.[3] The Commission should remove the GWP limit for the BUILD and TECH pilots in the Proposed Decision.

MCE supports multiple recommendations to address the GWP of refrigerants. First, MCE agrees with other parties that it is appropriate for the Commission to thread into the existing California Air Resources Board ("CARB") process to establish GWP limits.[4] Second, the Commission should authorize extra incentives for low-GWP refrigerants to send a market signal to immediately accelerate the transition to lower GWP refrigerants.[5] Third, the Commission should recognize the fuel-related greenhouse gas emissions from gas-fired appliances generally far outweigh the impacts of high-GWP refrigerant leaks from most heat pump technologies.[6] These actions will enhance the BUILD and TECH pilots and accelerate the market transformation objectives outlined in SB 1477 while addressing the GWP of refrigerants.

---

[2] CEJA-NRDC-SC Comments at p. 2, 4; CBIA Comments at p. 1; EBCE Comments at p. 2; BayREN at p. 2; SMUD Comments at p. 3; Rheem Comments at p. 3; VEIC Comments at p. 3-4; A.O. Smith Comments at p. 4.
[3] California Efficiency and Demand Management Council Opening Comments at p. 4.
[4] CEJA-NRDC-SC Comments at p. 3-5; CBIA Comments at p. 1; EBCE Comments at p. 2; BayREN at p. 3; SMUD Comments at p. 3-4; Rheem Comments at p. 4-5; VEIC Comments at p. 5; A.O. Smith Comments at p. 3-4.
[5] CEJA-NRDC-SC Comments at p. 5; CBIA Comments at p. 2; EBCE Comments at p. 3; BayREN at p. 3; VEIC Comments at p. 5; A.O. Smith Comments at p. 3.
[6] CEJA-NRDC-SC Comments at p. 4-5.

III. THE COMMISSION SHOULD SUPPORT LOW-INCOME AND EQUITY INTERESTS THROUGH THE SOLICITATION FOR THE TECH INITIATIVE

MCE agrees the TECH Initiative should have an acute focus on technologies that improve health, safety, and energy affordability and should explicitly prioritize the needs of low-income residential housing and disadvantaged communities.[7] MCE agrees that bidders for the TECH Initiative should include an equity plan to demonstrate how they intend to support market development for low-income, disadvantaged communities and customers.[8] While it is challenging to ensure rebates for upstream programs will benefit low-income customers, midstream outreach and incentives could be directed toward these communities. These equity plans should be a component of the bid scoring to ensure a focus on low-income and disadvantaged communities. MCE further agrees with CSE that a member of the Disadvantaged Communities Advisory Group should participate in the scoring and selection of the TECH implementor.[9] This will ensure there is expertise in reviewing and scoring the equity plans. Most market transformation activities will likely eventually benefit low-income and disadvantaged communities, particularly once they mature to the point that prices decrease. However, the TECH implementer should endeavor to include these communities along with early adopters that tend to have higher incomes. The Commission should adopt these proposals to ensure low-income and disadvantaged communities are an explicit focus throughout market transformation under SB 1477.

[7] Center for Sustainable Energy Opening Comments ("CSE Comments") at p. 3-4; GRID Alternatives Opening Comments ("GRID Comments") at p. 3; California Housing Partnership Corporation Opening Comments ("CHPC Comments") at p. 4-5.
[8] CSE Comments at p. 3-4.
[9] CSE Comments at p. 5-6.

IV. THE COMMISSION SHOULD ENCOURAGE INTEGRATION OF THE SB 1477 PILOTS WITH OTHER ENERGY PROGRAMS AND ELIMINATION OF BARRIERS TO INTEGRATION

MCE supports the recommendation for the BUILD and TECH programs to co-fund and collaborate with other energy programs in California.[10] Integration with all available energy-related programs should be a global focus for ratepayer-funded programs. This should be more than bringing brochures for related programs when meeting with a customer and should include meaningful backend and customer-installation integration. This can reduce administrative costs, enhance the experience for contractors and customers, and capture complementary opportunities. However, the TRC calculation for energy efficiency may be a barrier to program integration as costs for decarbonization measures would be included along with energy efficiency measures in the Total Resource Cost ("TRC") Test.[11] The impact is a powerful disincentive for energy efficiency projects to layer in decarbonization measures that may greatly reduce greenhouse gas emissions but may not cost-effectively reduce energy use. This policy tension must be resolved to allow for program integration. For this reason, MCE agrees with Recurve that energy efficiency projects should be able to exclude decarbonization measures that are not supported with efficiency funds from the TRC Test calculations.[12] For these excluded measures, both the costs and benefits should be excluded from the TRC Test calculations to avoid conflicting policies undermining progress toward the state's policy goals of reducing energy use and decarbonizing the energy supply.

---

[10] CEJA-NRDC-SC Comments at p. 13.
[11] BayREN Comments at p. 3; Recurve Analytics, Inc. Opening Comments ("Recurve Comments") at p. 2-3.
[12] Recurve Comments at p. 2-3.

V. CONCLUSION

MCE thanks Assigned Commissioner Randolph, Administrative Law Judge ("ALJ") Fitch, ALJ McKinney, and ALJ Rizzo for their thoughtful consideration of these reply comments on the Proposed Decision.

Respectfully submitted,

/s/ Michael Callahan
Michael Callahan
Senior Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
(415) 464-6045
mcallahan@mceCleanEnergy.org

March 9, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

OPENING COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE FINAL REPORT OF WORKING GROUP 3 CO-CHAIRS SOUTHERN CALIFORNIA EDISON COMPANY (U 338E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY

Evelyn Kahl
General Counsel
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, California 94521
415.254.5454
regulatory@cal-cca.org

Ann Springgate
Buchalter, A Professional Corporation
55 Second Street, Suite 1700
San Francisco, California 94105
415.227.0900
aspringgate@buchalter.com

Counsel to the
California Community Choice Association

March 13, 2020

TABLE OF CONTENTS

Table of Contents continued

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

OPENING COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE FINAL REPORT OF WORKING GROUP 3 CO-CHAIRS SOUTHERN CALIFORNIA EDISON COMPANY (U 338E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND COMMERCIAL ENERGY

Pursuant to the January 22, 2020 Administrative Law Judge's ("ALJ") Ruling Modifying Proceeding Schedule, the California Community Choice Association ("CalCCA")[1] respectfully submits these Opening Comments on the Final Report of Working Group 3 submitted by Co-Chairs CalCCA, Southern California Edison Company ("SCE"), and Commercial Energy.

I. INTRODUCTION AND SUMMARY

CalCCA thanks its Co-Chairs for their diligence, collegiality, and commitment to the process of creating consensus proposals that will benefit all customers. As noted in the Final Report, the Co-Chairs met regularly for many months, and shared and discussed numerous straw proposals. The result of this effort is a set of consensus proposals to help resolve the difficult issues addressed in this proceeding. CalCCA urges the Commission to adopt the consensus proposals put forward by the Working Group, which if adopted, will effect a significant improvement over the status quo and a large step toward meeting the Commission's goals of optimizing Investor-Owned Utility ("IOU") portfolios and reducing costs for all customers.

---

1 California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

However, more can be done to increase the value of these proposals. CalCCA urges the Commission to implement changes as soon as possible and to increase transparency of IOU operations so that all load-serving entities ("LSEs") have confidence that these changes will achieve the Commission's objectives for Working Group 3. These comments expand on and clarify the proposals put forward by CalCCA that did not achieve consensus in the working group. Specifically, CalCCA recommends the Commission:

- ✓ Allocate RA Attributes and RPS energy as soon as possible, through an interim procedure pending full implementation;
- ✓ Clarify that the IOUs' actions and inactions with respect to the Request for Interest ("RFI") and solicitation process for contract assignments and modifications are subject to disallowance risk;
- ✓ Require the IOUs to file their reports on the RFI and solicitation process annually in their respective Energy Resource Recovery Account ("ERRA") compliance application to enable regular review of optimization activities;
- ✓ Apply the Commission-approved Power Charge Indifference Adjustment ("PCIA") rate cap to additional costs associated with Commission approved Renewable Portfolio Standard ("RPS") buy-outs, assignments or terminations, recognizing that the IOUs' obligation to optimize their portfolio is not new;
- ✓ Allocate all Local Resource Adequacy ("RA") to all LSEs, based on load share, with no market offer.

II. CONSENSUS PROPOSALS ARE A SIGNIFICANT WIN FOR ALL CUSTOMERS WHO BEAR THE BURDEN OF THESE COSTS

A. Allocation of RA, RPS and GHG-free Energy Based on Load Share Equitably Transfers IOU Attributes and Energy to the Customers Who Paid for Them and Preserves Non-IOU LSE Autonomy

CalCCA strongly encourages the Commission to adopt the Co-Chairs' consensus proposals for allocation of RA, RPS and greenhouse gas ("GHG")-free energy based on each LSE's load share to ensure equitable cost sharing among all LSEs, and to transfer the value of PCIA-eligible energy and attributes to the non-IOU LSEs who have borne the costs for these products. Allocation of these PCIA-eligible attributes and energy is superior to an "excess sales" approach because it eliminates the need to address the complex issues of whether the IOUs should retain any of these attributes, and if so, how much, to serve as "buffers" or "uncertainty tranches." Allocation as proposed also solves disagreements regarding the timing of any such excess sales. The market offer construct proposed for System and Flex RA and RPS energy also creates additional opportunities for the IOUs to optimize the value of these attributes, and reflects the effect of LSEs' reporting and compliance obligations on the likely market for these attributes.

B. RPS and System and Flex Voluntary Allocation and Market Offers Preserve LSE Flexibility and Autonomy

Under the consensus proposal, LSEs may elect to either receive their share of PCIA-eligible System and Flex RA and RPS energy directly, or have customers receive economic consideration for these products through PCIA rates. The voluntary allocation of these products will be followed by a market offer of volumes declined. This voluntary allocation and market offer construct ("VAMO") provides an equitable means by which LSEs can elect to receive System and/or Flex RA and RPS energy directly as an allocation, have their customers receive economic consideration through PCIA rates, or choose a blend of the two options to suit their specific needs.

In addition to removing the challenges presented by buffers, uncertainty tranches, and sales timing encountered with the excess sales approach, the VAMO approach will provide liquidity to the market and is designed to help keep PCIA rates approximately where they are today. This approach also permits LSEs the flexibility to manage their procurement activities by choosing the volume of the IOUs' RA attributes and RPS energy to procure at the market price benchmark ("MPB") through an allocation.

Establishing the Spring market offer for System and Flex RA allows LSEs to fill a portion of their RA procurement volumes well in advance of compliance deadlines. Thus, demand should be high, as will revenues realized. Unsold attributes from the Spring market offer, together with any declined allocation volumes, will also be offered for sale in a Fall market offer. All unallocated RPS energy for the prompt year will also be offered for sale through an annual market offer process to be held by the IOU, who will be required to include in the market offer up to 35% of each LSEs' annual declined allocation share as long-term sales. Under the proposals the IOUs are able to participate in these market offers, and protections are built in to ensure the IOUs do not receive an undue advantage relative to other market participants.

The market offers proposed will ensure the sales of unallocated volumes of System and Flex RA and RPS energy and are designed to increase the markets for these attributes and to maximize their value. This will result in higher revenues, and therefore reduce PCIA rates for all customers.

1. Voluntary Allocation of GHG-free Energy Transfers Power Content Label and Clean Net Short Credit to Non-IOU LSEs, and the Allocation Should Be Tradeable

Because GHG-free energy resources are being paid for through the PCIA and the energy revenues are being realized by PCIA-paying customers, CalCCA supports a voluntary allocation of these attributes to PCIA-paying customers' LSEs. GHG- free energy will be allocated annually to LSEs who may choose to take their forecasted, vintaged, annual load share of either or both of two pools of GHG-free energy, nuclear and non-nuclear. Since not all LSEs can accept nuclear energy, CalCCA also supports the split of these resources into two pools, and the option for LSEs to choose allocation from either or both pools. LSEs accepting their allocations may claim the GHG-free energy deliveries on their Power Content Label ("PCL") and may claim credit toward their Clean Net Short ("CNS") procurement requirement.

There will be no market offer for unallocated GHG-free energy. Any rejected allocations will be reallocated proportionally to those LSEs who elect to receive their allocations. CalCCA urges the Commission to adopt its proposal that accepted allocations of GHG-free energy may be traded or sold, including the right to claim the benefits on PCL. The ability to trade or sell allocations will increase LSE flexibility in managing portfolios, and will also ensure that the full value of this energy is realized.

2. Full Allocation of Local RA Eliminates Complexity and Market Power

While the Local RA allocation proposal calls for full allocation, and is therefore less flexible for LSEs, the proposed allocation of Local RA avoids the complexities arising from the existing constraints and potential market power issues that might exist in certain Local RA-constrained geographical areas, particularly in disaggregated local areas. Because the allocation will be tradeable, however, LSEs will maintain flexibility and autonomy as they may choose either to use their allocations for compliance, or monetize their allocation by trading their allocated Local RA in the secondary market.

Trades or sales of LSEs' allocated RA also enables LSEs to manage their portfolios and act in the best interest of their customers. This may permit LSEs to sell their share of the PCIA Showing without having to sell other procured RA positions. Thus, trading also reduces the risk of stranding RA with an LSE who is long, and the risks that either Local RA is used for less valuable purposes, such as System or Flexible RA showing requirements, or simply remains unutilized. While recognizing the increased complication and administrative burden of a secondary market for trading RA, CalCCA urges the Commission to adopt this proposal, which creates a valuable tool for all LSEs, and ensures a valuable asset is used to full effect.

C. The RFI Process and Solicitation for Contract Assignments and Modifications Mandates IOU Action to Reduce High-Cost Contracts

The consensus proposal for the IOUs' RFI for contract assignments and IOUs' solicitation of proposals for contract modifications are proactive methods to achieve reductions in IOU contract costs. While opportunities for contract assignments and modifications may occur organically, CalCCA urges the Commission to adopt these proposals. The effect will be to ensure mass outreach to the IOUs' contracted generators and potentially spark creative thinking on the part of those sellers to propose mutually beneficial transactions. These processes will also allow other LSEs an opportunity to contract directly with generators currently bound by IOU contracts.

This consensus proposal essentially provides two “open seasons” for contract restructuring, and also provides for reporting and therefore greater visibility into the actions taken. CalCCA notes that the potential for these proposals to result in large reductions to outstanding contract costs, thereby benefiting all customers, greatly outweighs the cost of resources to implement the proposals. The Co-Chairs’ proposal limits the number of negotiations each IOU is required to enter into with respect to each RFI, which addresses IOU concerns regarding the resources that may have to be devoted to these efforts.

D. The Ratemaking Proposals are Equitable and Align with the Structure Established in Phase 1

1. Ratemaking Proposal for System and Flex RA and RPS Energy Is Equitable, Requiring Payment at the Benchmark for Attributes and Energy Received, But Valuing Unsold As Sales at $0

CalCCA initially proposed the ratemaking option that eventually became the consensus proposal. Under this treatment, the existing PCIA framework established by Decision18-10-019 is maintained. The inputs to the calculation, however, are modified to reflect allocation shares of System and Flex RA and RPS energy as purchases by those PCIA-eligible LSEs of the allocated volumes at the otherwise applicable MPB. In this way, the sales revenues received by the IOU for these allocations will offset the MPB value assigned to the products, minimizing any impact on the PCIA.

In the event that either System or Flex RA or RPS energy remains after the conclusion of the VAMO processes, those will be re-distributed among all LSEs at no cost and on a pro-rata basis according to their forecasted, vintaged, annual load shares (peak load shares, in the case of System and Flex RA). These re-allocated volumes will be treated as sales at $0/MWh ($0/kW-mo. in the case of System and Flex RA) and will be reported, along with the volumes re-allocated, by the IOUs to the Energy Division for the purposes of establishing the respective

MPBs. This reallocation ensures that all LSEs receive the value associated with the unsold attributes, since all will pay the PCIA increase resulting from the zero valuation of unsold volumes. The unsold attributes should be incorporated into the MPB at zero to ensure that the MPB appropriately reflects the market value of the attributes. LSEs can choose to use the unsold volumes for their own compliance purposes or may choose to sell the attributes in the secondary market themselves.

2. The Market Price Benchmark for Local RA Should Be Eliminated to Ensure Full Cost Recovery

The MPB for Local RA should be eliminated. Because all LSEs will receive the value of Local RA products through their allocated share of the attributes, there is no longer a need to reflect the value in the PCIA, either through a MPB valuation or sales credit against PCIA costs. Eliminating the MPB simplifies cost recovery and ensures full costs are recovered. A consequence of eliminating the MPB associated with Local RA is that PCIA rates may rise. While CalCCA advocates for the application of the rate cap to all PCIA increases, CalCCA recognizes that this increase in PCIA rates is unique. In exchange for the higher PCIA, each LSE receives a concrete benefit in the Local RA allocation. Because each LSE will receive a tangible, valuable benefit, a one-time adjustment to the PCIA rate cap to exclude the impacts of this change in the Local RA MPB methodology is justified. This is a unique situation and should not be precedential for other potential increases to the PCIA rate.

III. THERE SHOULD BE AN INTERIM ALLOCATION OF RA ATTRIBUTES AND RPS ENERGY TO TAKE EFFECT BEFORE ALL NECESSARY STEPS FOR FULL IMPLEMENTATION CAN BE COMPLETED

A. RPS Should be Allocated as Soon as Practical Following the Final Decision

The Co-Chairs aligned on a full implementation schedule that is based in part on changes needed in the IOUs' RPS Procurement Plan to incorporate the RPS VAMO process and the Commission's need to confirm a modified timeline for LSEs to submit and the CPUC and/or

CEC to calibrate LSEs' vintaged, annual load forecasts. The Co-Chairs have urged adoption of the modified timeline in Rulemaking19-11-009 in the second quarter of 2021.

However, given the value of the RPS energy in question and the length of time necessary to accomplish these steps, the Co-Chairs also proposed that an interim RPS voluntary allocation approach be pursued. In this interim process, RPS would be offered to LSEs for allocation on the basis of LSEs' actual, vintaged, annual load shares. There would be no market offer process. The Co-Chairs requested the Commission specify that during this transition period excess RPS generation, excluding banked Renewable Energy Credits ("RECs"), may be valued at $0/MWh for purposes of the PCIA only to the extent that it (i) is offered for sale by the IOU, (ii) remains unsold, and (iii) is in excess of the IOU's interpolated annual RPS compliance target.

SCE contends that even interim RPS energy allocations cannot commence before 2022 based on the need for updates to the IOUs' RPS Procurement Plans and to allow time "for the market to prepare for the new requirements."[2] CalCCA questions what preparation is required for an immediate allocation of energy based on each LSEs' proportional load share. CalCCA also questions the motives for seeking a delay. Since declined allocations will remain with the IOU, and each LSE, including the IOUs, will be entitled to their proportional load share of RPS energy, the IOUs' abilities to meet their RPS compliance requirements seem extremely unlikely to be "jeopardized" by an earlier interim allocation as claimed by SCE. [3] Thus, CalCCA urges the Commission to instead require the IOUs to amend their RPS Procurement Plans via motions to update, which could be requested as soon as practical following the Working Group 3 Final Decision. Allocations could commence 30 days following approval of the motions, thus permitting allocations to begin in 2021. In this way an equitable distribution of valuable RPS energy could be achieved almost immediately, to the benefit of all customers.

---

[2] Final Report at 63.
[3] *Id*.

B. RA Should be Allocated in 2021 for Compliance Year 2022 for System and Flex, and for Compliance Year 2023 and 2024 for Local RA

Due to the length of time anticipated for the regulatory decisions required for full implementation of the Local and System and Flex RA proposals, the Co-Chairs suggested that the VAMO for System and Flex RA commence in 2022 for the 2023 compliance year. The Co-Chairs propose that Local RA allocation also be implemented in the 2022 filing year, but only for the 2024 and 2025 compliance years due to the complexities of the multi-year Local RA requirement.

CalCCA, together with Commercial Energy, urges the Commission to adopt an interim implementation timeline for Local and System and Flex RA to allow for allocation beginning in 2021 for the 2022 System and Flex RA compliance year and 2021 for the 2023 and 2024 Local RA compliance years ("Interim Proposal"). As detailed in the Final Report,[4] CalCCA and Commercial Energy put forth a detailed timeline for this interim allocation. The proposed process calls for PCIA-eligible LSEs and the IOUs to agree on each LSE's vintaged, monthly peak load forecasts for each of their vintages. LSEs would have five business days to submit their System and Flex RA allocation elections following notification by the IOUs of the LSE's estimated eligible RA allocation volumes. Local RA allocations would be mandatory, as will be the case once the proposals are fully implemented.

The Interim Proposal provides for the IOUs and LSEs to align on forecasts and calls for allocation based on the best estimates for Local RA volumes available. This is a reasonable approach that will ensure that LSEs who have paid for Local RA attributes through the PCIA are able use these attributes in a timely fashion. Transferring attributes out of the IOUs' portfolios as soon as possible, so that other LSEs can utilize or monetize the attributes, is an important aspect of the Commission's stated goals for Phase 2 of the PCIA proceeding, which are to optimize the IOUs' portfolios and reduce costs.[5] In addition, an interim full allocation of Local RA will mitigate the impact of market power issues that may already be arising in certain Local

---

4 Final Report at 61-62.

5 D.18-10-019 at 97.

RA-constrained geographical areas. Leaving Local RA in the IOUs' portfolios for a further number of years, when a reasonable method of establishing allocations exists, is counterproductive and contrary to D.18-10-019.

IV. CURRENT STANDARDS SUBJECT THE IOUS TO DISALLOWANCE RISK BASED ON ACTIONS NOT TAKEN IN RESPONSE TO THE RFI AND SOLICITATION FOR CONTRACT ASSIGNMENTS AND MODIFICATIONS

A. IOUs Are Required to Manage Their Portfolios, Including Actions Taken and Not Taken in Response to RFIs, Pursuant to Standard of Conduct 4

The Commission holds authority to oversee and make disallowances based on both an IOU's action and its inaction under the proposed RFI and solicitation processes for contract assignments and modifications pursuant to Assembly Bill 57[6] ("AB 57") through the application of Standard of Conduct 4 ("SOC 4"). SOC 4 requires: "The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[7] The "reasonable manager standard" applies to review of that administration.[8] Prudent administration involves not only making sure that the IOU complies with the terms and conditions of each contract, but that the IOU makes efforts to manage its *overall* portfolio by taking other actions such as buy-outs, buy-downs and other contract modifications when the contracts are no longer needed or economic to serve bundled customers.

SCE contends that there are no "upfront, achievable standards" that obligate the IOU to accept, or pursue, or otherwise decline an offer from a counterparty to modify or terminate an existing procurement contract already approved for cost recovery. SCE further contends that absent such upfront, achievable standards, the IOU bears no disallowance risk under the prudent manager standard for declining to accept or pursue an offer from a counterparty to modify or terminate an existing procurement contract. To the extent the IOU reasonably administers its

6 Assembly Bill 57 (Stats. 2002, Ch. 835).
7 D.02-10-062 at 52.
8 D.05-01-054 at 15.

approved contracts pursuant to their terms and conditions, AB 57 guarantees the IOU cost recovery.

SCE claims the only standard applicable is that of Section 454.5(h),[9] which states, "[n]othing in this section alters, modifies, or amends . . . the commission's existing authority to investigate and penalize an electrical corporation's alleged fraudulent activities, or to disallow costs incurred as a result of gross incompetence, fraud, abuse, or similar grounds." This argument fails to consider the rest of Section 454.5, which includes exhaustive requirements for procurement planning. Subsection (h) does not limit the Commission's ability to disallow costs under other applicable standards.

Standard of Conduct 4 clearly applies. SOC 4 requires both prudent contract administration and least-cost dispatch in a two-part standard. The Commission specifically clarified SOC 4, stating, "[i]n administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs."[10] The Commission has upheld the reasonable manager standard for review of utility procurement plans through compliance review.[11] Citing D.02-12-069, the Commission has further elaborated that "[u]nder SOC 4, . . .compliance would consist of a showing of prudence for contract administration (for which the reasonable manager standard would apply) and a showing that resources were dispatched in a least cost manner."[12]

Moreover, the Commission has established that SOC 4 has a broad scope, as "the Commission's intent is to review contract administration, including least-cost dispatch."[13] It is clear SOC 4 review is not limited to dispatch decisions. In fact, the Commission has stated that "[SOC 4] 'involves management of the whole portfolio, including whether the dispatchable contracts were utilized in an optimum manner as compared to other utility resources,'"[14] and

---

9 Unless otherwise stated, all code sections refer to the California Public Utilities Code.
10 D.02-12-074, Ordering Paragraph 24b.
11 D.02-12-069 at 62, *modified on other grounds by* D.03-12-003.
12 D.05-01-054 at 15.
13 *Id*. at 12 (emphasis added).
14 D.03-06-076 at 25, *citing* ORA Response to Applications for Rehearing of D.02-12-074 at 3.

finding that this standard applies "to utility retained generation (URG) and pre-existing power contracts, and to new resources obtained pursuant to the approved procurement plans."[15]

B. If the Commission Determines that Standard of Conduct 4 Does Not Apply, The Commission Should Specify a Prudent Manager Standard for IOU Action and Inaction In Response to Contract Assignments and Modifications

While CalCCA contends that the applicability of SOC 4 is clear, if the Commission determines otherwise, it should in any case adopt a standard of review for IOU actions and inactions with respect to contract assignment and modification offers. Contrary to what the IOUs assert, Section 454.5(h) need not be the only applicable standard. This is not the first time the utilities have challenged the validity of SOC 4 in the context of other standards, and the Commission has dismissed these arguments in the past.[16] The Commission frequently imposes and administers standards for utilities that work in concert with each other. The Commission demonstrates this point when discussing the responsibilities of utilities under both Section 454.5 and the least-cost dispatch element of SOC 4:

> The main focus of the statute is "procurement transactions" and "procurement contracts." (See, e.g., §§ 454.5(c)(3), 454.5(d)(2).) The legislative history of section 454.5(d)(2) indicates that the Legislature's intent in enacting the statute was only to eliminate after-the-fact review of the procurement contracts themselves. (See, e.g., Assem. Floor Analysis, Assem. Bill No. 57 (2001-2002 Reg. Sess.) as amended June 24, 2002.) Nothing in the statute, nor its legislative history, indicates that the Legislature intended the statute to apply to dispatch of energy. Thus, any subsequent review of dispatch is not precluded by section 454.5(d)(2).[17]

There is no reason the longstanding "prudent manager" standard should not apply to IOU decisions with respect to action and inaction regarding contract assignments and modifications, in concert with the existing standards of Section 454.5(h). Under the prudent manager standard, "a utility has the burden to affirmatively prove that it reasonably and prudently operated and

---

15 *Id*.
16 *See, e.g.,* D.03-06-076.
17 D.03-06-076 at 25.

managed its system."[18] Proposals submitted by generators or other sellers to either assign or modify the IOUs' existing contracts, to the benefit of all rate paying customers, surely deserve serious consideration by the IOUs. Just as surely, ratepayers deserve the IOUs act prudently regarding both accepting and rejecting these proposals.

Though CalCCA continues to assert that SOC 4 applies, if the Commission declines to apply it here, the Commission should adopt a standard specific to the IOUs' action and inactions with respect to contract assignments and modifications to make clear the IOUs must do more than merely avoid gross incompetence or fraud.

V. THE COMMISSION SHOULD REQUIRE THE IOUS TO FILE REPORTS ON THE RFI PROCESS ANNUALLY IN THEIR ERRA COMPLIANCE APPLICATION

The Co-Chairs were unable to reach consensus on the issue of where the IOUs should be required to file their respective reports on the RFI and solicitation processes. CalCCA believes that in order to guarantee full transparency for LSEs, this report should be filed in each IOU's ERRA Compliance Application. The ERRA process is a well-established Commission process with well-established standards of review. Parties will naturally look to the ERRA Compliance Application for details of each IOU's portfolio optimization activities, and the results of the RFI process proposed in the Final Report should likewise be housed in that application. Finally, it is imperative to CCAs and other interested parties that the report filed be subject to discovery and rules pertaining thereto. Again, the ERRA Compliance process has an established discovery process and is the best fit for the filing of this report.

---

[18] D.18-07-025 at 3.

VI. ADDITIONAL COSTS ASSOCIATED WITH COMMISSION APPROVED RPS BUY-OUTS, ASSIGNMENTS OR TERMINATIONS SHOULD BE SUBJECT TO THE COMMISSION-APPROVED CAP ON THE PCIA RATE

A. IOUs Are Already Required to Optimize Their Portfolios and These Efforts Are Subject to the PCIA Rate Cap

Contract termination payments should not be excluded from the $0.005/kWh annual PCIA rate increase cap established by D.18-10-019. SCE and Commercial do not believe the upfront cost of buying out contracts was intended to be factored into the cap, based on the fact that these costs could increase the PCIA cost to customers and potentially trigger the cap every year. SCE and Commercial believe this is not what the Commission intended.

CalCCA disagrees. An IOU's responsibility to optimize its portfolio through the RFI is no more onerous than the requirement to optimize their portfolios today under AB 57 and the Standards of Conduct. In fact, SCE took pains to explain the scope of existing IOU portfolio optimization efforts.[19] These contract buy-outs or terminations are no different than other portfolio optimization efforts currently undertaken by the IOUs. These efforts are, of course, subject to the rate cap.

Because the IOUs continually perform these types of portfolio optimization activities, the Commission was fully aware of the potential for buy-outs or buy-downs when it adopted the cap in D.18-10-019. That the Commission chose not to make such transactions an exception from the cap demonstrates that it intended no exception. Thus, if the IOUs want to propose an exception to the cap on the PCIA rate increases due to these contract modifications, buy-outs or terminations, it should seek modification of the decision the Commission issued in Phase 1 of this proceeding.

Finally, CalCCA observes that there are other ways of addressing significant buy-out or buy-down costs. CalCCA proposed securitization of any such costs in its Phase 1 testimony.[20]

---

[19] *See, e.g.*, Final Report, Appendix D- Presentation of PCIA Phase 2- Working Group Three, Workshop No. 4, December 11, 2019, at slide 23.

[20] *See* Direct Testimony of Paul Sutherland, Barry Abramson, Joseph S. Fichera, and Hyman Schoenblum (CalCCA-1, Exhibits 3-A-D).

VII. LOCAL RA SHOULD BE ALLOCATED TO ALL LSEs BASED ON LOAD SHARE, WITH NO MARKET OFFER

Commercial Energy proposes a voluntary allocation of Local RA followed by a market offer of the unallocated Local RA[21] attributes declined. CalCCA and SCE propose instead a mandatory allocation of Local RA. CalCCA's and SCE's proposal achieves the goal of optimizing the IOU's PCIA-eligible portfolio through the proportional allocation of products and value to all customers – bundled and departed load – that bear cost responsibility.

LSEs expressed concerns throughout the Working Group 3 process about the IOUs not making sufficient Local RA capacity available to the market. If a full allocation model is adopted, potential market power issues that could arise in certain Local RA-constrained geographical areas are eliminated. A full allocation of all Local RA based on each LSE's proportional load share also removes from the equation consideration of how to deal with unallocated volumes, including if and when to hold a market offer.

CalCCA is cognizant that a full allocation model is less flexible for all LSEs. However, due to the unique conditions in the Local RA markets, the full allocation model is the most straightforward method to ensure all LSEs receive their proportional share of attributes, and costs. In addition, because Local RA allocations are tradeable in the secondary market, the perceived rigidity of the full allocation is mitigated. Any LSE that so desires can monetize its PCIA-eligible Local RA. CalCCA urges the Commission to adopt the full allocation model for Local RA.

---

21 Final Report at 30.

VIII. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

/s/ Ann Springgate

Ann Springgate
Counsel to the
California Community Choice Association

March 13, 2020

BN 39910455v1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	)))))))	Rulemaking 18-07-003 (Filed July 23, 2018)

INFORMAL COMMENTS OF THE JOINT CCA PARTIES ON RENEWABLES PORTFOLIO STANDARD WORKSHOP ON PROCUREMENT PLAN AND COMPLIANCE REPORT TEMPLATES

Justin Wynne
Braun Blaising Smith Wynne, P.C.
555 Capitol Mall, Suite 570
Sacramento, CA 95814
(916) 326-5812
wynne@braunlegal.com

Counsel for the Cities of Lancaster, Pico Rivera, San Jacinto, and Rancho Mirage

And on behalf of Apple Valley Choice Energy, Clean Power Alliance, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority

(collectively, "Joint CCA Parties")

Dated: March 19, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	))))))	Rulemaking 18-07-003 (Filed July 23, 2018)

INFORMAL COMMENTS OF THE JOINT CCA PARTIES ON RENEWABLES PORTFOLIO STANDARD WORKSHOP ON PROCUREMENT PLAN AND COMPLIANCE REPORT TEMPLATES

I. INTRODUCTION

The Joint CCA Parties submit the following informal comments on the *Renewables Portfolio Standard Workshop on Procurement Plan and Compliance Report Templates*, held on February 27, 2020. Prior to the February 27 workshop, the California Public Utilities Commission's ("Commission") Energy Division released a list of questions to help guide the workshop discussion. These informal comments provide an initial response to Energy Division's questions as well as respond to issues that were discussed during the workshop.

II. INITIAL RESPONSE TO WORKSHOP QUESTIONS

The Joint CCA Parties appreciate Energy Division staff's efforts to make improvements to the Renewables Portfolio Standard ("RPS") Program's reporting templates and submission process. The Joint CCA Parties encourage further collaboration among staff and the retail sellers, and in particular urge staff to release draft versions of the various templates early enough in the reporting cycle to allow the parties to identify any potential errors and recommend improvements.

The Joint CCA Parties' initial responses to the Energy Division staff questions are provided below:

Question 1*: What broad improvements should staff consider making for each set of filing spreadsheets to reduce redundancies and resolve errors (e.g. readability, file size, efficiencies in submission process, etc.)?*

A. Regular RPS Reporting and Process Webinars

During the February 27 workshop, Energy Division staff stated that for each reporting cycle, a significant amount of staff time and resources are devoted to responding to questions about RPS compliance requirements as well as questions about how to complete and submit the required forms. Staff asked if there would be support for regular webinars in advance of filing dates to discuss these matters in a collective format.

The Joint CCA Parties strongly support the Commission holding regular, staff-led webinars in advance of the filing deadlines for the Procurement Plans as well as both the annual Compliance Reports and the final Compliance Reports. These webinars would provide a single forum where all the of the retail sellers could ask questions and come to a common understanding with staff regarding requirements and process. Such an approach would save Commission staff resources by reducing the number of questions that they would receive and would reduce the burdens on the retail sellers by eliminating any potential confusion.

In conjunction with these regular webinars, the Joint CCA Parties also recommend that Energy Division staff request feedback on and additional topics for the various guidance documents available on the Commission's RPS Compliance and Reporting website. These guidance documents currently include the "RPS Onboarding Guide," the "RPS Compliance Reporting FAQ," and the "Portfolio Content Category Classification Review Process

Handbook." Improving and expanding these documents is another simple way to reduce the administrative burdens associated with the filing requirements.

B. Process for Improvements to the Compliance Reporting Forms

As many parties mentioned during the February 27 workshop, the current Compliance Report template forms are not formatted in a way that easily accommodates the conversion of these documents into pdf format, which is necessary for the public service of these documents. The Joint CCA Parties support staff making improvements to these templates that would simplify, streamline, and potentially standardize the pdf conversion process. As a method for identifying these improvements, the Joint CCA Parties recommend that, for this year's annual RPS Compliance Report, staff release draft versions of the templates well in advance of the filing deadline and request that parties provide proposed improvements to the format and layout of various tabs within these templates. Based on this input, staff could then incorporate these changes into the final forms that will be used for reporting.

C. Other Improvements to Reporting Templates

In addition to the recommendations above, parties discussed a number of other worthwhile improvements to the RPS Compliance Report templates during the February 27 workshop. Staff should consider all of this potential improvements. In particular, the Joint CCA Parties support the following proposed changes: (i) using the same units (kWh/MWh/GWh) across all reporting forms to reduce the potential for user errors; (ii) eliminating the requirement to enter data for prior compliance periods to both reduce the administrative burden and reduce the likelihood of errors; and (iii) where possible, aligning the template format with the relevant WREGIS reports to facilitate simpler date transfer, such as in the 36 Month reporting tabs.

Question 2: *Parties have proposed integrating the RPS Procurement Plan quantitative information into the annual RPS Compliance Report, arguing that it would make filings more efficient for retail sellers and avoid reporting the same information in both filings. What are the primary areas of the RPS Procurement Plan quantitative information that can be incorporated into the annual RPS Compliance Report? Please use specific citations to the 2019 templates.*

A. Moving Quantitative Information to the Annual RPS Compliance Report

The Joint CCA Parties believe that there may be value in transitioning some or all of the quantitative information that is currently reported in the RPS Procurement Plans to the RPS Compliance Reports. The Joint CCA Parties look forward to evaluating any proposal for such a transition that is submitted by other parties, and may provide a response in reply comments.

Question 3: *Given the distinct purposes of the two filings and the ways in which the information is used for tracking procurement progress and evaluating compliance, what specific information should be eliminated from each of the filings, if any? For example, historical and forecasted RPS procurement is included in both filings. What is your opinion on limiting the Compliance Report to historical procurement data and Procurement Plan quantitative information section to forward-looking planning projections? Provide reasoning for or against limiting the procurement years reported.*

A. Elimination of Data from Reporting Templates

During the February 27 Workshop, several parties supported modifying the quantitative information included in the Procurement Plans to only be forward-looking and modifying the data reported in the RPS Compliance Reports to only be historical. The Joint CCA Parties generally support this proposal because it would eliminate unnecessary information that does not appear to be relevant to the purpose served by those respective filings. The RPS Procurement Plans assess a retail seller's procurement activities and planning efforts to ensure that it meets its current and future RPS requirements. Therefore, it is appropriate for the data that is reported as part of the RPS Procurement Plans to only cover the current and future compliance periods. The RPS Compliance Report is assessing actual procurement that is being counted toward compliance and so does not need forecast information to be included. The elimination of this data should serve to not only reduce that administrative burden associated with these filings, but will also reduce the likelihood of errors being made.

Question 4: *The data collected through these filings are used to inform the Legislature, CPUC and stakeholders on procurement progress of all retail sellers towards meeting the RPS requirements. The data is also used in Integrated Resource Planning modeling efforts. The IOUs submit a Project Development Status Report each month with information on their RPS contracts. All other retail sellers submit two filings per year, the Procurement Plan and the Compliance Report. What suggestions do you have to ensure that Energy Division has the most up to date RPS contract information for all retail sellers?*

A. More Frequent Reporting

Information relating to retail seller's renewable procurement activities is reported to the Commission multiple times a year, not only through the RPS Procurement Plan and RPS Compliance Report filings, but also through the integrated resource plan ("IRP") filing requirements and the power charge indifference adjustment ("PCIA") data requests. The consensus of the parties during the February 27 workshop was that these existing reporting requirements should be sufficient to meet the Commission's needs for both planning purposes and for reporting to the Legislature. Given the significant existing reporting burden on retail sellers, Energy Division staff should carefully evaluate the need for any additional reporting requirements. To the extent that specific information is identified that is needed for a purpose that serves an essential Commission function, the Joint CCA Parties recommend that staff work with relevant reporting entities to identify the best method for obtaining this information.

III. CONCLUSION

The Joint CCA Parties appreciate the opportunity to provide these informal comments to the Commission.

March 19, 2020

Respectfully submitted,

/s/

Justin Wynne
Braun Blaising McLaughlin Smith, P.C.
555 Capitol Mall, Suite 570
Sacramento, CA 95814
(916) 326-5812
wynne@braunlegal.com

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

OPENING COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON TRACK 1 PROPOSALS

Evelyn Kahl
General Counsel
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94521
415.254.5454
regulatory@cal-cca.org

March 6, 2020

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

OPENING COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON TRACK 1 PROPOSALS

Pursuant to the *Assigned Commissioner's Scoping Memo and Ruling* issued on January 22, 2020 ("Scoping Memo"), the California Community Choice Association[1] submits these comments on the proposals of the Energy Division Staff ("Staff"), the California Independent System Operator ("CAISO"), Southern California Edison Company and Shell Energy North America (US), L.P. ("SCE/Shell"), Morgan Stanley Capital Group Inc. ("MSCG") and Powerex Corp. ("Powerex") filed on February 28, 2020.

I. INTRODUCTION

CalCCA supports the Commission's effort to ensure that energy from imports shown for resource adequacy ("RA") compliance will be available to serve load when needed and appreciates stakeholders' detailed proposals to achieve this objective. While each proposal will enhance reliability, their impacts will vary in several respects:

- *Supply availability.* More restrictive eligibility requirements will reduce the scope of imports available for RA compliance; unnecessary restrictiveness will unreasonably increase the cost of achieving reliability.

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

- *Market power exercise.* Overly conservative firm transmission requirements will enable the exercise of market power in a highly concentrated transmission market, particularly to the California-Oregon Border (COB) and Nevada-Oregon Border (NOB), as demonstrated by MSCG.

- *Regulatory uncertainty.* More dramatic changes in past practices will increase regulatory uncertainty and, consequently, strand existing contracts and unnecessarily increase costs.

- *State authority.* Requirements that materially affect price-setting in the wholesale energy market create a greater risk of preemption by the Federal Energy Regulatory Commission ("FERC"), while requirements aligning squarely with CAISO market operation will best ensure cooperative federalism.

Taking into account these and other factors, CalCCA proposes adoption of import RA eligibility requirements that draw from the proposals advanced by the CAISO and MSCG ("Blended Proposal").

The Blended Proposal identifies eligible categories of RA resources providing energy or capacity using the framework advanced by MSCG, subject to varying requirements for each category. CalCCA proposes that five requirements of the Blended Proposal would be common to all resource categories:

1. At the time of showing, the contract must specify a source, including pseudo-tied or dynamically scheduled resources and individual or aggregated physical resources that are in excess of the host balancing authority ("BA") requirements.

2. The contract and attestation to the Commission must state that the supply has not been committed to other uses.

3. The contract and attestation to the Commission must confirm, consistent with existing requirements, that the product "cannot be curtailed for economic reasons, and either (a) is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher priority transmission or (b) specifies firm delivery point (i.e., is not sellers choice)."[2]

4. The shown import resources that clear the Day Ahead Market ("DAM") are subject to Real Time Market ("RTM") Must Offer Obligation ("MOO").

---

[2] *See* D.04-10-035 at 21-22; Workshop Report on Resource Adequacy Issues, R.01-10-024 and R.04-04-003, June 15, 2004, at 21.

5. The resource cannot be internal to the CAISO balancing area.

The requirements would differ in certain ways as required to deter speculative supply and ensure comparable levels of assurance that the resources will be available. Capacity or energy from resources that are not pseudo-tied or dynamically scheduled must either (a) provide telemetry or other operational data to the CAISO to enable verification of resource availability or (b) be subject to a $500/MWh DAM offer cap, which carries into the RTM MOO for cleared quantities.

In addition to these eligibility requirements, CalCCA proposes adoption of grandfathering rules to enable a transition and avoid stranding existing contracts and increasing customer costs. The new requirements should be adopted for application to the 2021 RA compliance year to avoid stranding contracts entered into for the current year. In addition, multi-year import RA contracts executed on or after the issuance of D.19-10-021 on October 17, 2019 but prior to the Track 1 final decision should be grandfathered for compliance purposes and allowed to expire under their own terms.

Collectively, these requirements will strongly deter speculative supply and ensure that energy from RA resources is available to meet California's requirements when needed. Importantly, however, these requirements will not unnecessarily reduce the supply of imports committed to support California's reliability, enable the exercise of market power by holders of transmission rights, strand existing contract value, or materially affect the operation of the wholesale energy market.

II. THE COMMISSION SHOULD BLEND THE CAISO AND MSCG PROPOSALS TO ESTABLISH IMPORT RA ELIGIBILITY REQUIREMENTS

The objective of the inquiry into import RA eligibility requirements aims squarely at reducing speculative supply. The Scoping Memo expanded on the OIR, noting the

Commission's concerns "related to speculative supply."[3] The Staff proposal likewise provided its proposal "to reduce speculation and potential gaming in the RA import market to ensure electricity is delivered into California when it is actually needed."[4] CalCCA supports this goal, but there are numerous ways to achieve this objective, and the adopted approach will have other important implications. The Commission must thus tailor its import RA rules to "reduce speculative supply" while retaining supply availability, mitigating the exercise of market power, avoiding unnecessary cost increases and minimizing wholesale market impacts.

All the stakeholder proposals – all from proponents with a strong interest in ensuring reliability – would reduce speculative supply and increase grid reliability. On balance, however, reliability would be best served by a blend of the CAISO and MSCG proposals, considering the implications of a change in current rules.

A. Eligible Products

The solution should begin by defining "specific sources" using the buckets identified by MSCG:

> *Dynamic Product:* Capacity from dynamically scheduled or pseudo tie resources[5]
>
> *Telemetry Product:* Capacity from specific source (including aggregation of physical resources, or balancing authority surplus) with telemetry or other operational data provided to CAISO
>
> *Attestation Product:* Capacity from specific source (including aggregation of physical resources, or balancing authority surplus) without telemetry, demonstrating availability through attestation

---

3 *Assigned Commissioner's Scoping Memo and Ruling*, Jan. 22, 2020, at 3.

4 *Administrative Law Judge's Ruling on Energy Division's Track 1 Proposal* (Staff Proposal), Feb. 28, 2020, Appendix A at 2.

5 Note that only the Dynamic Product would be listed on the Commission's NQC list; the other categories of resource would not.

Energy Product: Energy contract imported by LSE from specific source (including aggregation of physical resources, or balancing authority surplus)

MSCG recognizes that from the standpoint of speculative supply risk, these resource categories are not similarly situated, and thus its proposal differentiates requirements to provide comparable assurances that the supply will be available when needed. CalCCA generally supports this approach, with minor modifications.

CalCCA supports elements of the CAISO's requirements to ensure the resources are committed to the RA program. CAISO proposes that imports:

- Provide source specific information at the time of the resource adequacy showings;
- Provide an attestation or other documentation that the resource adequacy import is a specific resource, aggregation of physical resources, or capacity in excess of the host balancing authority area or supplier's existing commitments that is dedicated to CAISO balancing authority area needs

Additionally, the Commission should require eligible contracts to specify that the supply is "surplus" to the supplier's existing commitments.

B. Firm Transmission

The CAISO also proposes "the Commission and CAISO require firm transmission delivery for all resource adequacy imports be demonstrated at the time of monthly showings."[6] To avoid negative, unintended consequences described below, CalCCA supports continued application of the Commission's approach to firm transmission. Contracts and attestations to the Commission must confirm that the product "cannot be curtailed for economic reasons, and either (a) is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher priority transmission or (b) specifies firm delivery point (i.e., is not seller's

---

6 *Id.* at 5.

choice)."[7] In addition, as the CAISO notes, the "Commission should also consider if penalties or other enforcement actions are necessary in the case that delivery is not made via firm transmission."[8]

Taking the more restrictive approach the CAISO proposes would unnecessarily reduce the availability of reliable imports, increase costs, and subject LSEs to market power in the firm transmission market. Requiring a supplier to commit firm transmission a month ahead, with no certainty that its supply will be needed, will discourage participation in the RA market. And if a supplier chooses to make this commitment, it will come at a steep price to customers. In addition, as MSCG demonstrated in its proposal, only four parties have firm transmission rights on both the BPA NW Network to Big Eddy and the Southern Intertie (Big Eddy to NOB) and one party controls nearly 80% of the 1,209 MW of NOB rights.[9] This presents a significant challenge for other sellers to obtain source-to-sink firm transmission in advance of the transmission being released to the market for use by more economical resources, and therefore would reduce supplies. Mandating a month-ahead showing of firm transmission likely will provide little or no more incremental benefit than a contract provision, attestation and penalty, but will certainly reduce supply or, alternatively, increase costs unnecessarily.

C. Complementary CAISO Market and Tariff Changes

CalCCA further supports certain aspects of the CAISO's proposed complementary market and tariff changes to support its proposal, including:

- Requiring attestations that all import resource adequacy supply included on resource adequacy supply plans is surplus, has not been committed to others, and will not be otherwise sold or relied upon to meet other areas needs after monthly showings;

---

7 *See* D.04-10-035 at 21-22; Workshop Report on Resource Adequacy Issues, R.01-10-024 and R.04-04-003, June 15, 2004, at 21.

8 CAISO Proposal at 6.

9 MSCG Proposal at 11.

- Requiring verification to ensure the resource specific supply remains available to the CAISO markets through the operational timeframe; and
- Clarifying that only source specific supply can qualify as resource adequacy import capacity.

Making changes to the CAISO tariff, rather than simply the Commission's rules, ensures *all* LSEs – not just Commission-jurisdictional LSEs – rely only on resources that demonstrate a higher level of certainty of availability. CalCCA supports these changes, subject to two clarifications. First, "source specific supply" should be defined to include not only Dynamic Products by Telemetry, but also Attestation and Energy Products as defined above. Second, the CAISO should require verification of availability in the operational timeframe for only Dynamic Products (through the RTM MOO) and Telemetry Products (through Telemetry); as discussed below, Attestation and Energy Products are subject to offer caps in the DAM and, if cleared in the DAM, the RTM.

CalCCA does not, however, agree with the CAISO proposal to modify its "market participation models to extend Must Offer Obligations to the Real-Time Market for all MWs included on resource adequacy showings…."[10] With other measures in place, this measure is unnecessary, likely to reduce the efficiency of the Energy Imbalance Market ("EIM") and could increase customer costs.

The RTM MOO is unnecessary for all imports for several reasons. First, the CAISO will have visibility of the Dynamic Product and Telemetry Product resource performance, and CAISO's DAM will have access to the bids below $500/MWh for the Attestation Product and Energy Product resources. In addition, CAISO's Day Ahead Market Enhancements Straw

[10] CAISO Proposal at 10.

proposal contemplates that CAISO will be able to address the uncertainty between the DAM and RTM by procuring imbalance reserves, taking into consideration both internal and external resources. The measure would likely reduce the efficiency of the EIM by tying up transmission that otherwise could have been used to dispatch more efficient resources. Finally, as explained more fully below, particularly at CAISO's northern interties, there is significant concentration of firm transmission, leading to the potential for significant cost increases to California consumers For these reasons, CalCCA supports retention of current CAISO rules, which impose a RTM MOO on imports only when they receive a DAM award.

D. Offer Requirements

CalCCA agrees with MSCG that more should be required of resources that are not pseudo-tied or dynamically scheduled. These resources should be required to provide added security by (1) providing telemetry or other operational data to the CAISO to confirm availability or (2) when no physical verification is provided, adhering to an offer cap of $500/MWh that would apply in the DAM and the RTM (when the resource clears the DAM).[11]

CalCCA's proposal is summarized in Appendix A.

III. THE STAFF PROPOSAL IS UNNECESSARILY RESTRICTIVE AND WILL INCREASE REGULATORY UNCERTAINTY, REDUCE SUPPLY AVAILABILITY, AND INCREASE CUSTOMER COSTS

The exercise of deterring speculative import RA supply requires consideration of several important issues, including the interaction of any requirements with not only reliability, but supply availability, market power, regulatory uncertainty, stranded costs and impacts on the wholesale market. The solutions presented in this Track range on a spectrum, with differing impacts in these areas. The Staff proposal is on the conservative edge of the spectrum and risks

---

[11] MSCG Proposal at 7.

supply reduction, market impacts and stranded costs. While CalCCA shares the Staff's aim of ensuring the availability of import energy when needed to support California reliability, there are less draconian approaches than those proposed by Staff.

The Staff Proposal will unnecessarily limit supply availability from import resources. First, it defines "resource specific" to include only pseudo-tied and dynamically scheduled resource specific resources,[12] unnecessarily excluding specific groups of resources whose availability could be demonstrated through other means. Second, while the Staff Proposal appears to permit reliance on resources that are not pseudo-tied or dynamically scheduled, in reality it does not. The proposal limits imports to energy contracts – a significant change in the current framework – and then essentially requires self-scheduling during availability assessment hours ("AAH").[13] These restrictions will naturally limit the pool of suppliers willing to provide import RA contracts to support California reliability.

The Staff Proposal also carries the potential to materially impact the wholesale market regulated by the FERC. By mandating the price bid by non-resource-specific import energy (*i.e.*, self-scheduling for all import RA), thus restricting the way energy is sold at wholesale and bid in CAISO markets, the Staff Proposal infringes on FERC jurisdiction. Where a state law or program is so "tethered" to, or directly impacts participation in, the wholesale market, FERC would be justified in challenging the state's action.[14]

The Staff Proposal may also create unintended consequences by hampering the state's environmental policy goals. In particular, the self-scheduling requirement may increase the

---

[12] Staff Proposal at 4.

[13] Staff Proposal at 5.

[14] *Hughes v. Talen Energy Mktg., LLC.*136 S. Ct. 1288 (2016).

evening ramp flexibility needs, as resources that are not contracted for RA rush to come offline so they do not conform to the market signal associated with self-scheduling during AAH. The market then may see a sharp decrease of resource supply immediately before AAH, which would require maintaining a large number of fast-ramping flexible resources, which are likely to be natural gas resources. This could potentially increase GHG emissions and create an unintended environmental consequence that is inconsistent with the goal of decarbonizing the grid.

For these reasons and recognizing that no other stakeholder proposes going to the Staff's extreme, the Commission should reject the Staff Proposal as unnecessarily and unreasonably restrictive.

IV. UNDER ANY PROPOSAL, THE COMMISSION SHOULD GRANDFATHER EXISTING CONTRACTS TO ADDRESS THE RECENT REGULATORY UNCERTAINTY SURROUNDING IMPORTS AND MITIGATE THE RISK OF STRANDED CONTRACT VALUE

Under any proposal the Commission adopts, it must take into account the impact of uncertainty in its regulations over the past year, both surrounding D.19-10-021 and Track 1 of this proceeding. Ongoing and material changes in rules risk stranding contracts executed by LSEs and, consequently, increasing customer costs. As the Commission did in modifying RA rules in 2004 and 2005, it should adopt transition rules to mitigate the risk of any such impacts.

The Commission considered a similar problem in 2005 and came to the conclusion that it must provide for notice, a phase out, and grandfathering to effectuate new RA rules. The Commission began to consider issues surrounding the use of Liquidated Damages ("LD") contracts for in-state resources in the RA program, but "did not definitively state an intention … to terminate their usage."[15] It thus concluded that "D.04-10-035 did not constitute fair notice to

[15] D.05-10-042 at 63.

LSEs that, as of October 29, 2004, they should only enter into new LD contracts with the understanding that they were at risk that those contracts would not qualify" for RA compliance.[16] The Commission clearly and accurately concluded: "[n]or did any other event prior to today constitute such notice."[17]

Recognizing the need for notice, the Commission carefully constructed a phase-out process to protect existing contracts. The Commission:

- ✓ Grandfathered LD contracts executed before the date of D.05-10-042;[18]
- ✓ Established a sunset date, making clear that "LD contracts will not count for purposes of RA showings after December 31, 2008."[19]
- ✓ Established step-down maximum limits for LD contracts, as a percentage of an LSE's RA portfolio, during the phase-out years 2006-2008.[20]

Finally, and most succinctly, the Commission stated:

> [B]y phasing out the ability of LD contracts to count in LSEs' RAR showings, we are not abrogating those contracts as has been claimed. The contracts will remain in effect until they expire on their own terms.[21]

The Commission should provide equally for existing contracts in the context of a final decision in this Track.

CalCCA proposes that the Commission minimize impacts by providing for implementation of any new rules no earlier than the 2021 compliance year. Any other approach risks impairing contracts already executed and submitted for showings. This is particularly true of the Staff proposal, which relies on Maximum Cumulative Capability (MCC) bucket

---

16 *Id.*

17 *Id.*

18 *Id.*

19 *Id.* at 64.

20 *Id.* at 65.

21 *Id.* at 66.

definitions;[22] since MCC buckets are currently undergoing redefinition in Track 2, implementing the Staff Proposal for 2020 would exacerbate uncertainty and increase stranded costs.

In addition, the Commission should mitigate the risk of stranding any multi-year forward system RA contracts. The Commission has encouraged forward contracting, and some LSEs have responded to that encouragement with multi-year contracts, anticipating an eventual move to a multi-year construct like local RA. To the extent an LSE has executed a multi-year system RA contract, the Commission should not "reward" the LSE's efforts by effectively creating stranded costs. CalCCA thus proposes that the Commission grandfather any multi-year system RA contract executed on or after October 17, 2019 (the issuance date for D.19-10-021) and allow it to count for compliance until it expires under its own terms.

V. CONCLUSION

For all of the foregoing reasons, CalCCA requests adoption of the Blended Proposal.

Respectfully submitted,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl
General Counsel

March 6, 2020

---

22 Staff Proposal at 5.

APPENDIX A

Source	Firm Transmission	CAISO Tariff Changes
Dynamic Products: Capacity from dynamically scheduled or pseudo tie resources	Firm from source to CAISO	• Attest that supply is committed surplus that will not otherwise be sold • Require verification through the existing RTM MOO to ensure the resource specific supply remains available to the CAISO markets through the operational timeframe; and • Clarify that only source specific supply can qualify as resource adequacy import capacity.
Telemetry Products: Capacity from specific source (including aggregation of physical resources, or balancing authority surplus) with telemetry provided to CAISO	The contract and attestation must confirm that the product "cannot be curtailed for economic reasons, and either (a) is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher priority transmission or (b) specifies firm delivery point (i.e., is not sellers choice)." Penalties could apply for failure to delivery using firm transmission	• Attest that supply is committed surplus that will not otherwise be sold • Require verification through telemetry to ensure the resource specific supply remains available to the CAISO markets through the operational timeframe; and • Clarify that only source specific supply can qualify as resource adequacy import capacity.
Attestation Products: Capacity from specific source (including aggregation of physical resources, or balancing authority surplus) subject to attestation	Same as Telemetry Product firm transmission requirements	• Attest that supply is committed surplus that will not otherwise be sold • Clarify that only source specific supply can qualify as resource adequacy import capacity • Impose $500/MWh offer cap in DAM and in RTM when awarded in DAM
Energy Products: Energy contract imported by LSE from specific source (including aggregation of physical resources, or balancing authority surplus)	Same as Telemetry Product firm transmission requirements	• Same as Attestation Product

APRIL FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 Filed September 28, 2017

MARIN CLEAN ENERGY NOTICE OF ORAL AND WRITTEN EX PARTE COMMUNICATIONS TO DISCUSS THE PROPOSED DECISION ON CENTRAL PROCUREMENT OF THE RESOURCE ADEQUACY PROGRAM

Daniel Settlemyer
Regulatory & Legislative Policy Assistant
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6658

April 27, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 Filed September 28, 2017

MARIN CLEAN ENERGY NOTICE OF ORAL AND WRITTEN EX PARTE COMMUNICATIONS TO DISCUSS THE PROPOSED DECISION ON CENTRAL PROCUREMENT OF THE RESOURCE ADEQUACY PROGRAM

Pursuant to Public Utilities Code Section 1701.3(h)(2) and Rule 8.2, and 8.4 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE"), hereby provides notice of *ex parte* communications in Rulemaking ("R") 17-09-020.

I. Oral *Ex Parte* Communication

On April 24, 2020 at approximately 10:30 AM, David Peck, Interim Energy Advisor to President Batjer met with the following individuals from MCE: Dawn Weisz, CEO; Shalini Swaroop, General Counsel and Director of Policy; and Nathaniel Malcolm, Policy Counsel. Brian Goldstein, Principal Consultant for Pacific Energy Advisors was also in attendance as a representative for MCE. The communication took place via teleconference. MCE initiated the communication and no written materials were provided.

During the meeting, the representatives from MCE discussed the Proposed Decision on Central Procurement of the Resource Adequacy ("RA") Program, issued on March 26, 2020 in proceeding R.17-09-020 ("Proposed Decision").

MCE raised concerns that several regulatory changes, including the recent Proposed Decision, have caused significant regulatory uncertainty, therefore creating undue market volatility and increased costs for MCE customers. In addition to increasing market uncertainty, MCE noted that the Proposed Decision would undermine CCA procurement innovations, especially regarding local clean resources. MCE also noted that allowing LSEs to continue their efforts on developing local RA would spur innovation, such as MCE's recently released Request for Offers for Clean RA.

MCE recommended a residual approach to central procurement whereby a Load Serving Entity ("LSE") would maintain its RA obligation to procure local RA. At a minimum, MCE urged the Commission to revise the Proposed Decision to: (1) allow grandfathering of local resources that the Commission had previously required LSEs to procure to enable LSEs to obtain a direct financial credit for the local attributes of such resources; and (2) allow LSEs the option to receive a direct financial credit for local preferred resources an LSE elects to show to the CPE.

II. Written *Ex Parte* Communication

As a follow up to its April 24 oral *ex parte* meeting with David Peck, MCE provided a separate written ex parte communication with David Peck on April 27, 2020. This communication consisted of an email and an attachment that are included as Attachment A to this notice. Pursuant to Rule 8.2(3), this communication is being served to all parties on the same day it is being sent to the decisionmaker.

Respectfully submitted,

/s/ Daniel Settlemyer

Daniel Settlemyer
Policy Assistant
MARIN CLEAN ENERGY
1125 Tamalpais Ave
San Rafael, CA 94901
Telephone: (415) 464-6658
Facsimile: (415) 459-8095
E-Mail: dsettlemyer@mceCleanEnergy.org

April 27, 2020

ATTACHMENT A:
WRITTEN COMMUNICATION

Shalini Swaroop <sswaroop@mcecleanenergy.org>

MCE RA RFO

Dawn Weisz <dweisz@mcecleanenergy.org> Mon, Apr 27, 2020 at 3:58 PM
To: david.peck@cpuc.ca.gov
Cc: Shalini Swaroop <sswaroop@mcecleanenergy.org>, Nathaniel Malcolm <nmalcolm@mcecleanenergy.org>

Hi David,

It was great to meet with you on Friday to discuss resource adequacy costs and issues. As promised, I have attached here the Clean RA RFO that MCE released in early April. Feel free to reach out if you have any questions.

In the meantime take care and stay safe,

Dawn

Dawn Weisz

CEO | MCE

mceCleanEnergy.org

dweisz@mceCleanEnergy.org

415.464.6020

1125 Tamalpias Ave. San Rafael, CA

2020 MCE Clean RA RFO_Final 20200406 (002).pdf
976K

MCE | My community. My choice.

Request for Offers
MCE 2020 Clean Resource Adequacy Solicitation
April 6, 2020
Procedural Overview & Instructions

I. Introduction and Product Description

MCE, a California joint powers authority, seeks qualified energy suppliers and developers to participate in MCE's 2020 Clean Resource Adequacy Request for Offers ("Clean RA RFO") solicitation. The purpose of MCE's Clean RA RFO is to contract for clean RA resources to phase out the use of fossil-based RA resources over the next ten to fifteen years.

MCE is administering this Clean RA RFO in an effort to procure a capacity product that does not rely on fossil fuel inputs throughout the delivery term, or transitions away from all fossil fuel inputs over the delivery term. For example, capacity products without fossil fuel inputs could include:

1. The use of renewable hydrogen in new build or existing generation sources to reduce or eliminate the carbon intensity of a generation facility
2. The use of renewable natural gas produced by facilities such as dairies, wastewater treatment plants, or landfills as fuel stock for natural gas generation facilities
3. Any collection of long duration generating technologies that is carbon free/neutral across the entire production chain (i.e., collection of renewable energy resources, battery storage, and other forms of dispatchable and clean resources)

   If the renewable fuel will be mixed with fossil fuel for generation, a path must be presented to convert the generating unit to full carbon free production within the first six years of any delivery term.. Capacity products that can achieve carbon-free production earlier in the term will be prioritized during the selection process.

By participating in MCE's 2020 Clean RA RFO process, respondents acknowledge that they have read, understand, and agree to the terms and conditions set forth in this Request for Offer Procedural Overview & Instructions. MCE reserves the right to reject any offer that does not comply with the requirements identified herein. Furthermore, MCE may, in its sole discretion and without notice, modify, suspend, or terminate the Clean RA RFO without further liability to any organization or individual. The Clean RA RFO does not constitute an offer to buy or create an obligation for MCE to enter into an agreement with any party, and MCE shall not be bound by the terms of any offer until MCE has entered into a fully executed agreement.

Offers pursuant to this RFO must be received by MCE not later than 5:00 P.M. Pacific Prevailing Time on the dates outlined in Section V.

II. About MCE

With offices in San Rafael and Concord, MCE is a public, not-for-profit agency which operates California's first community choice aggregation ("CCA") program as well as various complementary energy-related programs.

MCE's primary focus is reducing energy-related greenhouse gas emissions by providing electricity customers with a supply portfolio that utilizes a minimum 60% renewable energy, a 100% renewable energy service option (available to all customers on a voluntary basis), and groundbreaking energy efficiency, demand response, and energy storage programs. Consistent with the CCA service model, MCE determines the sources and suppliers of the energy it procures, and PG&E continues to manage the transmission and distribution of such energy to MCE customers. MCE maintains investment grade credit ratings of Baa2 from Moody's and BBB from Fitch. Members of MCE include the County of Marin and its towns and cities, the County of Napa and its towns and cities, the County of Contra Costa and its cities of Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Richmond, San Pablo, San Ramon and Walnut Creek, and the city of Benicia. MCE also plans to expand its territory over the coming years to include additional communities in Solano County.

III. Required Content of Offers

Offers must include all the following components with sufficient detail to support MCE's evaluative process (using the criteria in Section IV). To be deemed a complete, conforming offer, each offer shall:

a. Be submitted electronically via the following email address, mcerfo@pacificea.com by 5:00 P.M. Pacific Prevailing Time on the due date as shown in Section V
b. Include the following information:
    - Detailed technology specifications including an explanation of how the technology meets MCE's "Clean RA" product definition defined in Section I
    - All relevant commercial terms including, but not limited to:
        i. Price in $/kW-month (no escalators)
        ii. Volume (MW/month)
            - Minimum size of 1 MW
        iii. RA product attributes (i.e., qualification for system, local, and flexible RA)
        iv. Term
        v. Start date
        vi. Credit support
        vii. Location
    - Financing Plan
    - Interconnection Study or Interconnection Agreement if new development project
    - Project development/conversion timeline as applicable

MCE encourages 2020 Clean RA RFO respondents to emphasize quality as opposed to quantity when considering the submittal of multiple responses. MCE will accept multiple pricing offers, but only where it relates to different online/start dates or conversion timelines for existing resources. Furthermore, MCE will only accept offers for resources and technologies that are 100% "clean" per the description in Section I; offers deemed low carbon, but not 100% "clean," will be deemed non-conforming and rejected from the solicitation process. Respondents may also submit offers for more than one project.

IV. Evaluation Criteria

MCE will evaluate responses in consideration of a common set of criteria, a partial list of which is included below. This list may be revised at MCE's sole discretion and includes:

a. Overall quality of response, inclusive of completeness, timeliness, and conformity;
b. Project technology and its alignment with MCE's criteria for Clean RA;
c. Price and relative value within MCE's supply portfolio;
d. Project location and local benefits, including local hiring and prevailing wage considerations;
e. Project development status, including but not limited to progress toward interconnection, deliverability, siting, zoning, permitting, and financing requirements;
f. Qualifications, experience, financial stability, and structure of the prospective project team (including its ownership);
g. Environmental impacts and related mitigation requirements; and
h. Development milestone schedule, if applicable.

V. Key Deadlines and Submission Requirements

MCE's 2020 Clean RA RFO will be administered based on the following schedule:

Issue RFO	**4/6/2020**
Vendor Q&A Window	**4/6 – 4/20/2020**
Submission Deadline	**5/4/2020, 5:00 P.M. Pacific Prevailing Time**
Short-list Notification	**5/18/2020**
Final Selection(s)	**6/1/2020**
Finalize Contract(s)	**7/19/2020**

a. *Notice of Intent to Offer:* A Notice of Intent to Offer is not required, however, it is useful for the evaluation process. No later than the deadline for submitting questions, all parties interested in responding to this RFO are encouraged, but not required, to notify MCE via email of the intent to submit an offer. This notice creates no obligation to submit a proposal but will ensure that interested parties are copied on MCE's future correspondence related to the 2020 Clean RA RFO. Notices must be sent to mcerfo@pacificea.com and should include the company's name and email contact information, referencing "**MCE 2020 Clean RA RFO – Notice of Intent to Offer**" in the subject line.

b. *Deadline for Questions.* Any questions related to the content of this RFO must be submitted to the RFO Manager at mcerfo@pacificea.com during the "Vendor Q&A window". Please see Section VIII, below, for additional information regarding questions submitted to MCE related to the 2020 Clean RA RFO.

c. *Deadline for Responses.* All responses to questions will be posted weekly.

d. *Submission Deadline*. To be eligible for consideration, offers must be submitted electronically via the following email address, mcerfo@pacificea.com by 5:00 P.M. Pacific Prevailing Time on May 4, 2020.

e. *Supplier Interviews/Q&A.* As necessary, MCE may submit clarifying questions to certain respondents or conduct interviews, based on information provided in the offer package. MCE shall retain the right, in its sole discretion, to request information without notifying other respondents. MCE shall establish due dates for any request(s) for additional information, which shall be communicated to the affected respondent(s).

f. *Response Evaluation and Supplier Notification.* Following its review of proposed responses and clarifying materials, as well as any interview(s) that may be conducted during this process, MCE will notify all selected suppliers of its intent to pursue contract negotiations. Those suppliers not selected during this process will be notified accordingly.

g. *Contract Approval and Execution.* MCE anticipates that the selection process will be completed by approximately the end of May 2020 as indicated above in the solicitation timeline table. Please note that full execution of a contract is likely to occur after this date and is subject to MCE Board approval.

VI. Supplier Diversity and Labor Practices

Consistent with the California Public Utilities Code and California Public Utilities Commission policy objectives, MCE collects information regarding supplier diversity and labor practices from project developers and their subcontractors regarding past, current and/or planned efforts and policies. Each Respondent will be required to complete a Labor Practices questionnaire as part of its offer package (please see MCE's Open Season Offer Form). Additionally, pursuant to Senate Bill 255, which imposes new supplier diversity reporting requirements on CCAs, Respondents that execute a PPA with MCE will be required to complete a Supplier Diversity questionnaire.

MCE does not give preferential treatment based on race, sex, color, ethnicity, or national origin; providing such information to MCE will not impact the selection process or good standing of executed PPAs.

VII. General Terms and Conditions

MCE's Reserved Rights

MCE may, at its sole discretion, withdraw this Request for Offers at any time, and/or reject any or all offers submitted without awarding a contract. MCE also reserves the right to negotiate any price or provision as well as accept or reject any or all parts of each offer, whatever is deemed to be in the best interest of MCE.

Respondents are solely responsible for any costs or expenses incurred in connection with the preparation and submittal of an offer or proposal. MCE shall be held harmless and free from any and all liability, claims, or expenses whatsoever incurred by, or on behalf of, any person or organization responding to this RFP.

All data and information furnished by MCE or referred to in this RFP are furnished for the Respondent's convenience. MCE does not guarantee that such data and information are accurate and assumes no responsibility whatsoever as to the accuracy of such data or its interpretation.

During the evaluation process MCE may request from any respondent additional information which MCE deems necessary to determine the respondent's ability to perform the required services. If such information is requested, the respondent shall provide such information within a commercially reasonable amount of time.

Public Records

All documents submitted in response to this Request will become the property of MCE upon submittal, and will be subject to the provisions of the California Public Records Act and any other applicable disclosure laws. Upon submission, all proposals shall be treated as confidential until the selection process is completed. Once a contract is awarded, all proposals shall be deemed public record. MCE is required to comply with the California Public Records Act as it relates to the treatment of any information marked "confidential." Respondents requesting that portions of its submittal should be exempt from disclosure must clearly identify those portions with the word "Confidential" printed on the lower right-hand corner of the page. Each page shall be clearly marked and separable from the proposal in order to facilitate public inspection of the non-confidential portion of the proposal. MCE will consider a respondent's request for an exemption from disclosure; however, if MCE receives a request for documents under the California Public Records Act, MCE will make a decision based upon applicable laws. Respondents should not over-designate material as confidential, and any requests or assertions by a respondent that the entire submittal, or significant portions thereof, are exempt from disclosure will not be honored.

VIII. Questions

To promote accuracy and consistency of information provided to all participants, questions will only be accepted via email to MCE's RFO Manager at mcerfo@pacificea.com with the subject line of such emails reading "**MCE 2020 Clean RA RFO Question**." Please note, the deadline for submitting questions is indicated in Section V above.

MCE will attempt to respond to submitted questions within a week of receipt. MCE will post the questions and responses to the solicitation page of MCE's website. Additionally, MCE reserves the right to combine similar questions, rephrase questions, or decline to answer questions, at its sole discretion. All questions must be submitted through the above process.

Thank you for your interest!

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2017)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION COMMENTS ON PROPOSED DECISION ON CENTRAL PROCUREMENT OF THE RESOURCE ADEQUACY PROGRAM

Evelyn Kahl
General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
(415) 254-5454
Regulatory@cal-cca.org

April 15, 2020

Table of Contents

Table of Contents continued

SUMMARY OF RECOMMENDATIONS

1. Adopt a Central Procurement Model That Fully Incentivizes LSE Procurement of Local Preferred Resources or Energy Storage. Adopt the Settlement Agreement as a detailed, implementable residual central procurement model that will advance progress toward the Commission's reliability and climate goals. In the alternative, modify the PD to incorporate a financial crediting mechanism for LSEs that "show" local RA resources to the CPE to avoid undermining incentives for the development of local preferred or energy storage resources by LSEs.

2. Improve the CPE Procurement Process. To bring greater clarity to the CPE procurement process and protection for non-IOU LSEs and their customers:

- *Direct*, rather than encourage, CCA representation on the PRG and permit the CCA community – not other PRG members – to select the representative.
- Limit CPE contracts to three years and to RA-only products, prohibiting the CPE from any broader procurement without a full application and a Commission-administered public review process.
- Direct a holistic examination of the IE/PRG approach to procurement oversight to ensure its integrity in the context of central procurement on behalf of other LSEs' customers and to ensure that these mechanisms operate as more than a rubber stamp for CPE procurement choices.
- Direct the CPE to give LSEs notice of CPE awards not fewer than six months before the annual system and flexible RA compliance deadlines and notice of the system and flexible RA allocation by the CPE not fewer than five months before these deadlines to enable LSEs to procure resources efficiently to meet their requirements.

3. Adopt a Cost Allocation Mechanism That Reflects LSE-Specific Cost Causation. Employ an LSE-specific generation-side charge using the methodology developed for purposes of the IRP procurement track in the central procurement process.

4. Limit the Term of the IOU as CPE. Adopt an IOU-CPE model as an interim measure pending development of a more permanent, durable, multi-attribute RA framework with a non-IOU CPE.

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2017)

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION
COMMENTS ON PROPOSED DECISION ON CENTRAL PROCUREMENT OF THE
RESOURCE ADEQUACY PROGRAM**

The California Community Choice Association ("CalCCA")[1] respectfully submits these comments pursuant to Rule 14.3 of the Rules of Practice and Procedure on the March 26, 2020, proposed *Decision on Central Procurement of the Resource Adequacy Program* ("PD").

I. INTRODUCTION

The PD rewinds the central buyer debate back to November 2018, when the Commission issued a proposed decision adopting a full central procurement model with the investor-owned utilities ("IOUs") as the central procurement entities ("CPE").[2] Recognizing that a "broad range of parties" opposed this model[3] and acknowledging the "lack of a consensus as to a central procurement mechanism,"[4] the Commission deferred its decision and directed parties to explore "workable implementation solutions" for central procurement."[5] Despite the investment of hundreds if not thousands of hours of time by private and public sector parties over the past year to develop alternatives, and a coherent integrated proposal presented by the Settlement Parties, the PD dusts off the prior proposed decision and adds a bit of window dressing.

---

1 California Community Choice Association represents the interests of 20 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

2 *Proposed Decision Refining the Resource Adequacy Program,* Nov. 21, 2018, at 7-19.

3 D.19-02-022 at 14.

4 *Id.* at 17.

5 *Id.*, Ordering Paragraph 4 at 45.

While purporting to strike a "reasonable balance between the residual and full procurement models,"[6] the PD's "hybrid" model is in effect a full procurement model with IOUs in the central role. The PD model fails to achieve the objectives that originally drove the development of a central buyer, contravenes statutory directives, ignores commercial realities, and leaves many questions – particularly the CPE procurement process – unanswered. Most critically, the PD undermines incentives for load serving entities ("LSEs") to develop resources in constrained local areas, including preferred or energy storage resources; this failure does not align with the state's reliability or climate objectives.

CalCCA urges the Commission to reject the PD and, instead, adopt the Settlement Agreement to correct these errors. The Settlement Agreement presents an integrated, detailed model designed to address the issues identified by the Commission in D.19-02-022. If the Commission declines to adopt the Settlement Agreement, *it is critical to modify the PD to preserve the incentives for LSEs to locate new resources in constrained local areas* (1) adopting a financial crediting mechanism for LSEs that chose to "show" preferred resources or energy storage to the CPE, and (2) adopting a cost allocation mechanism that reflects LSE-specific cost causation. In addition, the Commission should:

- ✓ Improve the CPE procurement process to add oversight to IOUs' choices and conduct to add transparency and reduce the CPE's discretion to provide a layer of additional protection for other LSEs and their customers;
- ✓ Adopt a cost allocation mechanism that reflects LSE-specific cost causation; and
- ✓ Limit the duration of the adopted program to the earlier of the implementation of a more permanent, durable multi-attribute resource adequacy ("RA") central procurement structure or three years of CPE operation.

Proposed Conclusions of Law, Findings of Fact and Ordering Paragraphs are provided in Appendix A to support these recommendations.

II. THE HYBRID MODEL DOES NOT REPRESENT A REASONABLE BALANCE BETWEEN THE RESIDUAL AND FULL PROCUREMENT MODELS

A. In Effect, the PD Model Is a Full Procurement Model

The PD advances a "hybrid" local RA central procurement model, which it claims represents "an appropriate, reasonable balance between the residual and full procurement models."[7] The PD's model is neither a hybrid nor a reasonable balance. In practical effect, the

[6] PD at 24.
[7] *Id*.

PD presents a "full" procurement model that forfeits the key benefits of a "residual" procurement model.

Key distinctions among central procurement models lie in two areas: (1) the ability of LSEs to determine the generation resources used to serve their customers, and (2) cost allocation. In these respects, the PD and full models are effectively the same. In both models:

- The CPE procures 100 percent of collective local RA requirements;
- An LSE's only option to monetize local RA value for the benefit of its customers is to bid the resource to the CPE; and
- All customers, by rate class, pay the same rate for local RA resources regardless of the LSE that serves them.

The only difference between the PD and full models is that an LSE may "show" local RA resources to the CPE to reduce the CPE's procurement on behalf of all LSEs, with the value of the resource socialized among all customers. As discussed below, this is a distinction without a difference, since there is virtually no economic incentive or rational reason for an LSE to make such a showing. Providing LSEs an opportunity to gift their resources as a subsidy to other LSEs' customers does not create a reasonable compromise between residual and full procurement models.

B. The PD Model Reduces Incentives to Develop Preferred or Energy Storage Resources in Constrained Local Areas Impairing Both Reliability, Local Resilience and Climate Goals

1. A Residual Model Creates Incentives for an LSE to Develop Preferred Resources in Local Areas

From an LSE's perspective, a residual model offers two critical benefits that a full model cannot. First, a residual model ensures that an LSE can monetize the *full* value stream of its resource in a market where local RA commands a premium. It achieves this end by providing an LSE *direct* credit for the local RA resources it procures for its load. Without this assurance, a new local preferred or energy storage resource pursued for other reasons –renewable portfolio value, resiliency or system RA – may not pencil out. Under these circumstances, and contrary to California's reliability and climate objectives, an LSE may elect not to pursue resources in a local area, including preferred and energy storage resources.

A local RA premium may play a material role in an LSE's decision whether to locate a project in a local area. In determining whether a project is economic, an LSE will look at the full value stream for the resource (i.e., energy, system/flex RA, local RA, renewable porotfolio standard ("RPS") and resiliency). The local RA premium, while varying in time and location, can be significant and carries the potential to be the determining factor in a project decision. The Energy Division's 2018 Resource Adequacy Report shows that average local RA prices were 25 percent to 38 percent higher than the system RA value.[8] As discussed below, the PD places this value at risk by leaving uncertainty about whether the CPE will select the LSE's local resource in its solicitation.

In addition to this explicit value component for in-front-of-the-meter ("IFOM") resources, a residual model provides a second benefit for behind-the-meter ("BTM") resources. A residual model, like the Settlement Agreement's model, assigns requirements or costs based on an LSE's peak load share. Consequently, a customer's cost will be affected by the LSE's load shape and, more specifically, its peak load. If an LSE reduces its peak load under a residual model, its customers' costs will decline because the LSE is obligated to buy relatively less local RA. Because peak load is the primary driver of the need for local capacity resources, a cost allocation mechanism linked to peak load is crucial.

This effect, combined with an LSE's procurement of resources to serve its customers, results in the customers paying for local RA based on their LSE's individual performance. Incentives are not muted through a socializing of costs, as they are with the PD model. The potential to reduce California electric customer costs and achieve cost effective greenhouse gas reductions and reliability should be front and center when the Commission deliberates the value of adopting a new CPE model.

2. The PD Model Ignores Commercial Realities

Parties, including CalCCA, contend that a full procurement model cannot adequately incentivize the development of local resources.[9] The PD states that it "does not believe that a hybrid procurement model reduces the incentives for LSEs to develop new local resources,"[10] yet expressly acknowledges that "an LSE may not get the full local value for itself." The PD justifies undermining incentives by suggesting that socializing costs among all customers is somehow "equitable" and that eliminating leaning -- a questionable goal, as discussed in Section II.E. -- is more important than procurement incentives.[11]

---

8 *See* 2018 Resource Adequacy Report, August 2019, Table 9. Capacity Prices by Local Area, 2018-2022 at 30.
9 *See* PD at 25.
10 *Id*.
11 *Id*.

The PD's unsubstantiated policy rhetoric ignores commercial realities in the electricity sector. The primary way in which the full and PD models permit monetization of local RA value is for the LSE to bid its local resource into the CPE. Two problems arise with this option: there is no assurance that the resource will be taken by the CPE and, if it is, the LSE must also give up the resource's system or flexible RA to the CPE because the RA attributes are bundled.[12] The full and PD models also permit an LSE to retain its local resource to meet its system and flexible RA requirements; this approach, however, sacrifices any local RA premium in the value stream.

The full and PD models differ only in one respect: the PD allows an LSE to "show" its local resource to the CPE. This feature, however, is a distinction without a difference. Because "shown" local RA will only reduce the collective requirement the CPE must meet, and the LSE will receive no *individual* credit needed to finance the procurement, there is virtually no incentive for an LSE to make this choice. Indeed, to give credibility to the PD's illusion of choice would require a belief that an LSE will make a showing because it trusts that all other LSEs will do the same – a naïve view of a competitive market. In fact, by crediting the benefit of expenditures by an LSE to all customers, this structure creates a significant cost shift and subsidy by the LSE customers bearing costs of the resource and express "leaning."

Not only do the full and PD models fail to provide LSEs *individual* credit for their procurement, they fail to assign costs based on the costs an LSE actually causes on behalf of its customers. Both models contemplate fully socializing all of the CPE's purchases, resulting in a uniform Cost Allocation Mechanism ("CAM") charge for all customers – regardless of LSE -- distinguished only by customer class. Consequently, if an LSE makes efforts to reduce its peak load through behind the meter preferred or energy storage resources – today the allocation factor for RA requirements – its customers receive no direct benefit, including cost reduction. The benefit accrues only to all customers collectively as the CPE's procurement requirement is reduced. Moving away from the central principle of cost causation reduces important incentives present in today's residual model and the Settlement Agreement's model.

C. The PD Model Does Not Advance the Commission's Original Objective for a Central Buyer: Reducing "Out of Market" CAISO Procurement

The 2018 Scoping Memo initiated the formal public debate regarding central procurement. It identified a central buyer as one approach "to reduce further out-of-market RA

---

12 PD at 37.

procurement, such as multi-year Local RA program and/or one or more central buyers (e.g., the large investor-owned utilities)….[13] It provided no additional reasoning for examining central procurement. Two problems have caused the California Independent System Operator ("CAISO") "out of market" backstop in the past – collective deficiency and market power exercise -- and the PD does not solve either problem.

The PD purports to address collective deficiency as a driver for CAISO backstop procurement but does no better in this regard than the Settlement Agreement. The reality is that collective deficiency – whether under a full or residual procurement model -- can be assessed by the CAISO only after procurement has been completed and the local resources of all California LSEs, not just CPUC-jurisdictional LSEs, have been shown to the CAISO.[14] The Settlement Agreement provided the RA-CPE the opportunity to procure resources to address collective deficiencies and to socialize the costs of that procurement following any determination by the CAISO that a deficiency remains.[15] In contrast, the PD does not discuss exactly how the CPE will anticipate and preempt collective deficiencies. Presumably, however, if a collective deficiency remained, the CPE would procure the needed resources to cure the collective deficiency and socialize the costs. Thus, the Settlement more clearly addresses the procedure for addressing these circumstances. At worst, there is no difference in the potential to avoid backstop procurement to address collective deficiencies.

The PD also does nothing to limit the potential need for CAISO backstop procurement to address market power. The PD gives "the CPE discretion to defer procurement of a local resource to the CAISO's backstop mechanisms, rather than through the solicitation process, if bid costs are deemed unreasonably high." This construct is no different than today: if LSEs cannot procure local RA at prices that are reasonable, they can seek a waiver and, implicitly, default the procurement to CAISO backstop. In other words, while the buyer has changed, the market conditions that buyers may face, such as an exercise of market power, have not. The best that can be said is that the Commission would collect information on generator bidding under

---

13 *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, Jan. 18, 2018 (2018 Ruling), at 4; *see also id.* at 6 (citing a central buyer as a solution for "reducing potentially costly backstop procurement").

14 *See generally* CAISO *Business Practice Manual for Reliability Requirements*, §8.2.3.

15 Joint Motion for Adoption of a Settlement Agreement, Aug. 30, 2019, at 4 and Term Sheet, §III.E. at 4.

this approach.[16] However, such information gathering cannot be the basis for fundamentally abrogating the rights of LSEs to control procurement of resources to serve their customers. And, critically, there is no basis in the record for the PD's implicit conclusion that the CPE will be able to procure resources at a price that is lower than the price LSEs would pay procuring on their own customers' behalf.

D. The PD Violates Public Utilities Code §380(b)(5) and §380(h)(5)

The Legislature made abundantly clear – not once, but twice in §380 – that a key objective of the Commission's reliability oversight is to preserve CCAs' self-procurement autonomy. Section 380(b)(5) requires the Commission to "*[m]aximize* the ability of community choice aggregators to determine the generation resources used to serve their customers." Further, §380(h)(5) requires the Commission to ensure "community choice aggregators can determine the generation resources used to serve their customers." The PD fails to meet these requirements.

Under the PD, CCAs cannot choose "the resources used to serve their customers." Instead, the CPE makes that choice by building a single portfolio that will serve all customers, and the CCA's customers will have their local RA needs met by that portfolio. And by naming the IOU as CPE, the Commission effectively takes control of resource selection in lieu of local governments. The PD fails the statutory requirement on its face.

The CCA's ability to offer or "show" its resources to the CPE does not change this equation because the CPE, not the CCA, will be making the choices to build the portfolio to serve the CCA's customers. Moreover, as discussed in Section II.B., even those rights – to offer and show – present risk to the CCA and substantial economic downside.

While §380(f) permits the Commission to "consider a centralized resource adequacy mechanism," it does not permit the Commission to ignore all other requirements in the statute in implementing a central buyer. Any central buyer mechanism must, like the Settlement Agreement proposed, enable a CCA to choose the resources that will serve its customers. The PD does not comport with the Legislature's directives.

16 PD at 54.

E. The Record Does Not Support the Conclusion that "Leaning" Is an Actual or Material Problem That Justifies Undermining Local Development Incentives

The desire to prevent "leaning" by LSEs on more effective procurement by other LSEs appears to have been an important driver of the PD's approach. The PD notes parties' criticisms that a residual model does not account for resource effectiveness in addressing local constraints.[17] It also concludes:

> the hybrid model ensures that all LSEs (and the customers they serve) pay equitably for the portfolio of local resources needed to run the grid reliably, eliminating the incentive to lean on the portfolio of other LSEs, which may also lead to costly backstop procurement.[18]

The importance of the issue has never been quantified, nor does the record present actual evidence of LSE "leaning." It has been a purely rhetorical argument from the outset, starting with Energy Division's conclusion that "[i]t would be inefficient and unnecessarily expensive to procure resources that are not effective in meeting the contingency" because it could lead to procurement "over and above the requirement."[19] While directionally the incentives argument makes intuitive sense, is this issue sufficiently important to depart substantially from the current residual framework and limit LSEs' self-procurement autonomy? The record simply does not support a trade-off between theoretical leaning and statutorily protected LSE self-procurement autonomy.

In addition, effectiveness factors are not certain or predictable. As the CAISO's operating procedures explain, "[e]ffectiveness factors must be considered in conjunction with other factors affecting current system conditions and overall efficiencies," which include (but are not limited to) specific unit availability, transmission outages, impact on congestion to other paths, and relative costs."[20] As a result, as the Settlement Parties explained (and the CAISO did not rebut) "[t]he CAISO does not believe that it can clearly articulate a single ranking of resources with respect to a multiplicity of contingencies."[21] Finally, even if the assumption-driven effectiveness factors were reliable and predictable, the CAISO does not provide three-

---

17 PD at 13, 33.

18 *Id.* at 25.

19 *Track 2 Energy Division Staff Proposals: Multi-Year RA Requirement*, Jul 12, 2018, at 24

20 *See, e.g.,* CAISO Operating Procedure No. 2210Z, Version No. 27.5, Dec. 17, 2019, §1.1.

21 Joint Motion for Adoption of a Settlement Agreement, Aug. 30, 2019, Appendix A at 6, n.2.

year forward effectiveness factors[22] that would be needed to support consideration of effectiveness in a central procurement model.

Finally, the PD is internally inconsistent. The PD raises leaning as a concern over potentially higher costs for ratepayers.[23] At the same time, the PD authorizes (and arguably invites) excess procurement stating that it "does not preclude the CPE from …procuring in excess of the adopted percentages."[24] If the Commission is truly concerned about costs, it must modify the PD to prevent excess procurement and the resultant increased ratepayer costs.

F. The CPE Oversight Process Lacks Clear Boundaries and Reasonable Protections for CCAs and Their Customers

The PD contemplates a preapproval process for CPE procurement with "achievable standards and criteria for cost recovery."[25] In addition, in a departure from current requirements, the PD does not expressly require the advance review and approval of *any* contract – including contracts in excess of five years. Instead, it relies on an Independent Evaluator and the Procurement Review Group to oversee the CPE's solicitation and contract execution process,[26] "encouraging," but not mandating, CCA representation in the PRG.[27] While the PRG may make recommendations on the CPE's procurement choices, it has no authority to deny, change or approve any contract. Thus, the Commission will be ceding its approval authority – along with ratepayer protection -- to the CPE itself.

The procurement directives also lack any boundaries on what the CPE may procure. There is no limitation on the term of any commitment, raising the specter of the accumulation of long-term obligations and costs that will be borne by IOU and CCA customers for years to come. The magnitude of the current above-market PCIA costs suggest that the result could be devastating economically to the IOUs' competitors.

The CPE may also procure any attributes it chooses bundled with local RA. The CPE's choice will thus impact an LSE's system and flexible RA portfolio through the proposed attribute allocation. This will in turn alter the quantity of system and flexible RA LSEs need to procure. If the CPE selects RPS resources, it could also put LSEs in the position of bearing the market

---

22 *See supra* Section II.E.
23 PD at 25.
24 *Id.* at 39.
25 *Id.* at 48-49.
26 *Id.* at 47.
27 *Id.* at 46.

risk; LSEs' customers will pay for the RPS attribute through the CAM and presumably receive offsetting revenues if the CPE sells the attributes, leaving them at risk for changes in market value of the RPS attribute over time.

The Commission is not only unlawfully substituting the judgment of executives at for-profit IOUs for the judgment of the local elected officials that govern CCAs, it is doing so with minimal boundaries. CCAs are thus asked to "trust" the IOU (its competitor) and "oversight" by Independent Evaluator ("IE") (an unregulated third party). There is no requirement that the procurement undertaken by the CPE be in the CCA's best interest. This restricts CCA's procurement autonomy for local RA and provides minimal safeguards to protect against the massive stranded costs the IOUs – particularly PG&E – have accumulated in the PCIA.

The PD also gives short shift to the RA timeline, failing to clarify when the CPE solicitation or notification of award will occur and when an LSE will have notice of its allocated system and flexible RA attributes. The failure to address these issues introduces material uncertainty into the system and flexible RA procurement process; LSEs will not know how much RA they should expect to count towards their system and flexible requirements until they learn whether the CPE accepted their bid. Furthermore, the PD states that LSEs will not receive their final CPE procured system and flexible RA allocations until late September or early October.[28] This late allocation would leave LSEs with only a few short weeks to fill their remaining system and flexible RA positions prior to the October 31 compliance deadline. This compressed timeline is unreasonable, particularly given that the amount of flexible RA procured by the CPE is entirely unpredictable. LSEs would face significant Commission penalties for system and flexible RA deficiencies despite having had only a few weeks to fill positions after the CPE's allocation. LSEs attempting to avoid such penalties would risk over-procurement and added ratepayer costs.

Changes are required to bring greater clarity to the process and protection for non-IOU LSEs and their customers.

- The Commission should undertake a holistic examination of the IE/PRG approach to procurement oversight prior to ceding its authority; it is unclear to the public that these participants have ever operated as more than a rubber stamp for IOU procurement choices.
- Commission must *direct*, rather than encourage, CCA representation on the PRG and should permit the CCA community – not other PRG members – to select the

[28] PD at 56.

representative provided the holistic examination approach addressed above occurs.

- To prevent another long-term accumulation of stranded costs, contracts should be limited to three years and to RA-only products. The CPE should not be permitted to procure resources beyond these boundaries absent a full application and review process in which CCAs and other LSEs may participate.
- The Commission should establish the principle that LSEs must be given notice of CPE awards not fewer than six months before the annual system and flexible RA compliance deadlines and notice of the system and flexible RA allocation by the CPE not fewer than five months before these deadlines to enable LSEs to procure resources efficiently to meet their requirements. The Commission should immediately initiate coordination with all relevant stakeholders, including the Energy Commission, to achieve this timeline.

While these changes will improve the PD, they are not a substitute for the development of a more permanent, durable multi-attribute RA central procurement framework with a third-party CPE.

G. The PD Leaves Unanswered Questions

The Settlement Parties went to great lengths to consider the potential impact and equity of the Settlement model. The PD brushes over this detail and, instead, defaults back to the original full procurement model proposed in 2018 that engendered substantial opposition. It further takes a casual approach to analysis and design, perhaps too comfortable in its reach for existing mechanisms, such as the CAM, IE and PRG, that may not be suited to this particular purpose. What may be appropriate for an IOU's procurement on behalf of its own bundled customers might not make equal sense when the IOU is procuring on behalf of competing LSEs. The PD also fails to answer numerous foundational questions.

- The PD acknowledges the need to ensure competitive neutrality yet relies on neutrality rules that arose under different circumstances, depends heavily on the effectiveness of the IE and PRG, and calls on the CPE, IE, PRG and Energy Division to create a new code of conduct.[29] In short, competitive neutrality – a pivotal factor in the PD's choice of CPE – is left without resolution.
- The CAISO concluded that changes to CAISO processes and tariffs would be required to provide a list of essential reliability resources and effectiveness factors on a three-year forward basis.[30] Ignoring the CAISO guidance, the PD proceeds as if these factors are a reliable, predictable tool and directs the CPE to use effectiveness factors in selecting resources for its portfolio.[31]

---

[29] PD at 51-53.

[30] *Comments of the California Independent System Operator*, Sept. 30, 2019, at 3.

[31] PD, Ordering Paragraph 9.b., at 66.

- The PD's explanation of IOU bidding into the CPE solicitation lacks clarity and certainty.[32] The PD does not explain how the "PPA price" determined which costs are "fixed" for this purpose and how are they levelized. It also fails to address how any energy and ancillary service value of toll agreements would be handled.

Finally, the PD does not make a serious effort to address the primary issue that drives most parties toward a residual approach: how to monetize the local RA value of resources in which an LSE invests. For all of the reasons described above, the PD should be rejected as a permanent solution.

III. THE COMMISSION SHOULD REJECT THE PD IN FAVOR OF MODEL THAT BALANCES CENTRAL PROCUREMENT WITH INCENTIVES FOR SELF-PROCUREMENT OF PREFERRED AND ENERGY STORAGE RESOURCES

The PD fails to strike a reasonable balance between the full and residual procurement model and, consequently, fails to capture key incentives to drive development of preferred and energy storage resources by LSEs in local areas. The Commission should reject the PD in favor of the Settlement Agreement, which captures those incentives. Alternatively, it should modify the PD to incorporate direct financial credit for local preferred resources or energy storage shown to the CPE to provide the right incentives for development. It should further modify the PD to commit to restructuring central procurement charges to more accurately reflect cost causation and provide transparency and comparability to customers of the costs an LSE incurs to serve their load.

A. The Commission Should Adopt the Settlement as a Detailed, Workable Model That Will Drive Development Consistent with the State's Reliability and Climate Goals

The Settlement presents a detailed workable model for residual procurement, enhancing today's framework with the addition of a CPE. CalCCA observes that the Settlement had more unified support than any other proposal advanced in this process, including the full procurement model and Southern California Edison Company's hybrid model, which appears to be the basis for the PD model. The Settlement also examined key issues, such as load migration, the RA timeline, and cost allocation, with enough detail to provide an implementable solution. Most critically, however, the Settlement addressed the two critical features the PD lacks: (1) an incentive for LSEs to develop new preferred or energy storage resources in local areas, and (2) cost allocation that follows cost causation.

---

32 PD at 38.

CalCCA will not use its limited comment space to reiterate all of the benefits of the Settlement model, which are discussed extensively in the *Joint Motion for Adoption of Settlement*, submitted on August 30, 2019. CalCCA urges the Commission, however, to reject the PD in favor of the Settlement to encourage procurement actions that enhance local reliability and California's climate goals.

B. If the Settlement is Not Adopted, the Commission Should Modify the PD to Strike a Reasonable Balance between the Full and Residual Models

1. The Commission Should Adopt a Direct Crediting Mechanism Providing Compensation for LSEs Who Show Their Local RA to the CPE

The single most critical change the Commission can make to mitigate the PD's impact on LSE self-procurement of local resources is to approve a direct credit to individual LSEs who self-procure local resources – including existing, preferred or energy storage resources - and show the resources to the CPE. This mechanism is a simple modification from the PD's proposal, where LSEs can elect to show their local resources to reduce the overall local resource procurement need of CPE, while maintaining the system and flex attributes for their own compliance. This modification will avoid undermining the existing incentives driving LSEs to invest in local preferred resources or energy storage and also avoid stranding costs for LSEs who already procured resources at a premium price to meet future local RA requirements.

Because LSEs would have no local RA requirement, the credit would not take the form of a MW credit against a requirement, as it does today. Instead, the credit would be a financial credit to the LSE to enable it to monetize the local RA value of its resource. The simplest design of this mechanism would be to count the LSE's resource toward the collective local RA requirement only – without including the resource's system or flexible attributes -- and pay the LSE the premium of the local RA value for the resource over the most current system RA market price. The local RA value would be measured as the weighted average price of the resources procured by the CPE in the relevant local area or sub-area, if sub-area prices are available. If a price is not available for a particular local area, the weighted average price for all the local areas with a price could be used. The system value would be measured as the most recent 12-month weighted average system RA price reported to the Energy Division pursuant to D.19-10-001.[33]

[33] D.19-01-001 requires LSEs to report their RA prices to the Energy Division as frequently as quarterly to enable calculation of the Power Charge Indifference Adjustment. D.19-01-00, Ordering Paragraph 5, at 56.

2. The Commission Should Modify the Cost Recovery Mechanism to Reflect Cost Causation

The PD adopts the CAM as the cost allocation and recovery mechanism.[34] In selecting this mechanism, the PD appears to equate "equitable" cost allocation, as required by §380(h)(4), with "equal" or fully socialized cost allocation. This approach ignores California's decision to provide for competition in the provision of retail electric service, where customers pay prices for service based on their suppliers' procurement strategies. More importantly, it ignores the reduction in incentive that occurs for BTM resource development, as discussed in Section II.B.

Traditional CAM cost recovery is not the only solution. The Commission should be striving not to continue to socialize all costs, as if there were no distinctions among service providers or products, but to facilitate charges and bill presentations that reflect cost causation. The idea is not new to the Commission, as it is currently developing an LSE-specific cost allocation mechanism to address IOU backstop costs under an LSE-based procurement structure in the IRP procurement track.[35]

CalCCA proposes that the Commission adopt the principle that the allocation of CPE costs should reflect the cost causation on an LSE-by-LSE basis, subject to further refinement through a workshop process. At a minimum, the Commission should direct a holistic examination of the allocation of centrally procured costs in the context of a competitive retail market, along with the implications of bill presentation on transparency for customers.

IV. THE IOUS SHOULD BE PLACED IN THE CPE ROLE ONLY ON AN INTERIM BASIS WHILE A BROADER, MORE DURABLE FRAMEWORK IS DEVELOPED

CalCCA opposes placing the IOUs in the role of CPE. As noted above, the result will be to increase the portion of the generation resources serving CCA customers *procured by the CCA's competitor*. And, at this point, the PD does not provide measures that will ensure complete separation between the CPE and IOU procurement.

CalCCA is particularly concerned about placing PG&E in this role. PG&E's procurement costs will go up after emerging from bankruptcy. PG&E has testified in the bankruptcy investigation that it anticipates needing to post higher collateral as compared to pre-Chapter 11.[36] Higher costs associated with procurement by PG&E as the CPE could have been

---

34 PD at 43.
35 *Id.* at 26.
36 PG&E's Plan of Reorganization OII 2019, January 31, 2020 at 2-26—27, 3-5

avoided by individual LSE procurement with a residual model. Moreover, the Commission is asking CCAs to place their trust in an entity whose actions –*despite Commission oversight*— have not been in the public interest, including criminal liability for gas line explosions, wildfire damage, Public Service Power Shutoffs, bankruptcy and a litany of other offenses.

While IOUs as CPEs may be an acceptable near- and short-term approach, the Commission should clarify that the PD model is only a bridge to a more permanent, durable multi-attribute model the employs a competitively neutral third-party CPE. CalCCA recommends limiting the IOUs' term as CPE to the earlier of the implementation of a replacement model or three years.

V. OTHER CLARIFICATIONS

The PD states that "[t]he hybrid approach also allows individual LSEs to voluntarily procure local resources to meet their system and flexible RA requirements **and** count them towards the collective local RA requirements, providing LSEs flexibility and autonomy to procure local resources."[37] If, despite all of the contrary reasons presented in these comments, the Commission adopts the PD's hybrid approach unchanged it should carry this intent in Ordering Paragraph 4a.

VI. CONCLUSION

The California Community Choice Association appreciate the opportunity to submit these comments and request adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the proposed decision as provided in Appendix A.

Respectfully submitted,

Evelyn Kahl
General Counsel to the
California Community Choice Association

April 15, 2020

[37] PD at 24 (emphasis supplied); *see also* PD at 35 ("If the LSE shows the resource to reduce the CPE's local RA procurement (either in advance of the solicitation or as an offer that is not selected by the CPE), the LSE may still use the resource to fulfill its system and flexible needs.").

ATTACHMENT A

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

FINDINGS OF FACT

8. ~~A hybrid central procurement framework strikes~~ To strike a reasonable balance between the residual and full procurement models and ~~best addresses~~ ensure reasonable incentives for an LSE to develop preferred or energy storage resources in local areas, ~~the known challenges identified in the local RA market,~~ the central procurement model must (1) provide a financial crediting mechanism for LSEs who self-procure and show their preferred or energy storage resources to the CPE and (2) allocate costs based on the LSE cost-causation.

13. The requirements pertaining to an all-source solicitation process adopted in past Commission decisions may not be reasonable in the context of broader procurement by the IOUs on behalf of other LSEs – their competitors – and therefore further review of the processes, including the IE and PRG, in this context is necessary. ~~are reasonable guidance for procurement by a CPE.~~

16. It is reasonable to require a distribution utility that is serving as the CPE to bid its own resources into the solicitation at their levelized fixed costs, and the Energy Division should conduct a workshop to clarify the definition of "levelized fixed costs."

20. The CAM methodology is a cost recovery mechanism that does not follow principles of cost causation for individual LSEs and their customers. ~~allows the CPE to efficiently procure local resources and recover costs incurred~~.

NEW. Reasonable limitations on the CPE's procurement discretion, including a limit to 3-year contracts for RA only transactions, will better protect LSEs and their customers from the potential stranded costs that could arise if the CPE procures excess long-term resources.

NEW. Any contract that goes beyond the three-year, RA-only construct must be examined by the Commission through a full application in a public process.

~~25. A portfolio approval process, similar to that adopted in D.07-12-052, satisfies the Commission's objectives for a preapproval process.~~

~~30. It is reasonable to maintain the current RA timeline with adjustments for hybrid central procurement.~~

30. The RA timeline must provide LSEs adequate notice of whether their resources have been selected by the CPE in its solicitation and how much system and flexible RA will be allocated by the CPE on their behalf.

CONCLUSIONS OF LAW

5. PG&E and SCE should be designated as the central procurement entities for their respective distribution service areas on an interim basis pending development of a permanent, durable, multi-attribute central procurement model.

15. The CAM methodology does not adequately reflect the costs caused by each LSE and its load, and an LSE-specific generation-side charge should be adopted as the cost recovery mechanism to cover procurement costs associated with serving the central procurement function.

NEW. The CCA community shall identify a CCA representative to participate in any PRG that participates in review of CPE transactions.

ORDERING PARAGRAPHS

4.a. If a load serving entity's (LSE) procured resource also meets a local Resource Adequacy (RA) need, the LSE may choose to: (1) show the resource ~~to reduce the central procurement entity's (CPE) overall local procurement obligation~~ and receive a direct financial credit for any preferred or energy storage resource shown, (2) bid the resource into the CPE's solicitation, or (3) elect not to show or bid the resource to the CPE and only use the resource to meet its own system and flexible RA needs.

4.a. (See Section V of Comments) If a load serving entity's (LSE) procured resource also meets a local Resource Adequacy (RA) need, the LSE may choose to: (1) show the resource to reduce the central procurement entity's (CPE) overall local procurement obligation and use the resource to meet its own system and flexible RA needs, (2) bid the resource into the CPE's solicitation, or (3) elect not to show or bid the resource to the CPE and only use the resource to meet its own system and flexible RA needs.

NEW 6.f. CPE procurement is limited to three-year contracts for RA-only resources unless seeking Commission approval through a full application and public review process.

11. CPE costs, including administrative costs, shall be allocated based on cost-causation, differentiating costs caused by each LSE and its load, and shall be recovered through a generation-side charge. ~~The Cost Allocation Mechanism methodology is adopted as the cost recovery mechanism to cover procurement costs incurred in serving the central procurement function. The administrative costs incurred in serving the central procurement function shall be recoverable under the Cost Allocation Mechanism.~~

13. The Cost Allocation Mechanism (CAM) Procurement Review Group (PRG), as adopted in Decision 07-12-052, is authorized to advise the central procurement entity (CPE). The CPE shall consult with CAM PRG members (including Energy Division and an independent evaluator) to outline procurement plans, draft solicitation bid documents, and collect feedback regarding the solicitation process. The PRG shall include a CCA representative selected collectively by CCAs.

17. The central procurement entity shall establish a rule or procedure that will govern how confidential, market-sensitive information received from third-party market participants during

the solicitation process will be protected and what firewall safeguards will be implemented to prevent the sharing of information beyond those employees involved in the solicitation and procurement process. The central procurement entity shall file and serve the proposed rule into the successor Resource Adequacy proceeding, Rulemaking 19-11-009, <u>and the proposal shall be subject to review and comment by parties</u>.

21. The Resource Adequacy timeline outlined in Section 3.9 is adopted in anticipation of the 2023 compliance year and future years, <u>subject to the following requirements: the CPE shall give LSEs notice of CPE awards not fewer than six months before the annual system and flexible RA compliance deadlines and notice of the system and flexible RA allocation by the CPE not fewer than five months before these deadlines to enable LSEs to procure resources efficiently to meet their requirements</u>.

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REPLY COMMENTS ON PROPOSED DECISION ON CENTRAL PROCUREMENT
OF THE RESOURCE ADEQUACY PROGRAM**

Evelyn Kahl, General Counsel
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
regulatory@cal-cca.org

April 20, 2020

Table of Contents

SUMMARY OF RECOMMENDATIONS

1. Adopt a Central Procurement Model That Fully Incentivizes LSE Procurement of Local Preferred Resources or Energy Storage.

- Adopt the Settlement Agreement as a detailed, implementable residual central procurement model that will advance progress toward the Commission's reliability and climate goals.
- In the alternative, modify the PD to incorporate a financial crediting mechanism for LSEs that "show" local RA resources to the CPE to avoid undermining incentives for the development of local preferred or energy storage resources by LSEs. Apply the same crediting mechanism to existing local RA commitments to grandfather the resources for the benefit of the procuring LSE in recognition of the Commission's material rule changes.

2. Improve the CPE Procurement Process. To bring greater clarity to the CPE procurement process and protection for non-IOU LSEs and their customers:

- Permit the CCA community – not other PRG members – to select the representative.
- Limit CPE contracts to three years and to RA-only products, prohibiting the CPE from any broader procurement without a full application and a Commission-administered public review process.
- Direct a holistic examination of the IE/PRG approach to procurement oversight to ensure its integrity in the context of central procurement on behalf of other LSEs' customers and to ensure that these mechanisms operate as more than a rubber stamp for CPE procurement choices.
- Direct the CPE to give LSEs notice of CPE awards not fewer than six months before the annual system and flexible RA compliance deadlines and notice of the system and flexible RA allocation by the CPE not fewer than five months before these deadlines to enable LSEs to procure resources efficiently to meet their requirements.

3. Adopt a Cost Allocation Mechanism That Reflects LSE-Specific Cost Causation. Employ an LSE-specific generation-side charge using the methodology developed for purposes of the IRP procurement track in the central procurement process.

4. Limit the Term of the IOU as CPE. Adopt an IOU-CPE model as an interim measure pending development of a more permanent, durable, multi-attribute RA framework with a non-IOU CPE.

5. Reject PG&E/SCE Proposal to Eliminate the Obligation for the IOU to Bid Resources to the CPE. Allowing IOUs to retain discretion of when and what to bid into the CPE solicitation shifts costs from bundled customers to CCA and DA customers.

6. Reject PG&E/SCE Proposal to Move IOU Resources from the PCIA Portfolio to the CAM Portfolio. While the costs paid by the CPE to the IOUs for their resources will be recovered through the CAM, it is unnecessary, unsupported by the record and overly complex to move the entire resource to the CAM.

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REPLY COMMENTS ON PROPOSED DECISION ON CENTRAL PROCUREMENT
OF THE RESOURCE ADEQUACY PROGRAM**

The California Community Choice Association ("CalCCA") respectfully submits these reply comments pursuant to Rule 14.3(d) of the California Public Utilities Commission Rules of Practice and Procedure on Presiding Administrative Law Judge Debbie Chiv's March 26, 2020, proposed *Decision on Central Procurement of the Resource Adequacy Program* ("PD").

I. INTRODUCTION

The Center for Energy Efficiency and Renewable Technologies ("CEERT") makes a compelling case to "scrap the PD." CEERT explains: "We simply cannot afford to waste limited energy and capital on fighting the *no longer relevant problem of a perceived shortage of LCR* at the expense of new clean resource development," particularly in the face of the need for a COVID-19 economic recovery.[1] The PD presents a solution chasing a problem that may no longer exist; indeed, the solution does not even address the problems the Commission identified several years ago and would leave new problems in its wake.[2]

If the Commission insists on moving forward with a CPE in the midst of vast regulatory and economic uncertainty and criticism, it should not simply press on - as it has since mid-2018 – with an investor-owned utility ("IOU") centered full procurement model. Instead, it should take stock of the many proposed modifications and craft a more efficient, cost-effective and lawful model that drives the right incentives to achieve California's climate goals.

Opening comments show a strong preference for a residual central procurement entity ("CPE") model.[3] While the reasons for parties' preferences vary, they center largely on the need for load-serving entity ("LSE") procurement autonomy and a structure that aligns incentives for LSEs to procure resources in constrained local areas. At a minimum, however, these and other parties propose a direct, LSE-specific credit for local resources "shown" by LSEs to the CPE[4] to correct investment incentives.

---

1 CEERT Comments at 7 (emphasis supplied); *see also Tenaska Comments*.

2 CalCCA Comments at 2-11; *see also* MRP Comments at 5-7.

3 Comments of AWEA at 3-4, CalCCA at 12, CAISO at 6 (consider residual for system and flex); Calpine at 5, CESA at 2-3, Engie at 8, IEP at 3, LS Power at 6, Middle River Power at 13, NRG at 1, 7, Shell at 2, SDG&E at 9, TURN at 2, Vistra Energy at 1-2, WPTF at 3.

4 Comments of AWEA at 3-4, CalCCA at 13 (preferred and energy storage resources), Calpine at 8-9, CESA at 4-6, LSA/SEIA at 4-5, NRG at 7-8, SDG&E at 3-4, Shell at 6-8, Sunrun at 9 (preferred resources), TURN at 2 (non-gas resources only); Vistra Energy at 5, WPTF at 7-8.

CalCCA urges the Commission to recognize these preferences and examine the wide-ranging flaws of the PD's approach. While a residual CPE model, if any, is the right answer to the questions presented in this proceeding, the Commission should at a minimum provide for a direct financial credit for "shown" resources. Specifically, it should (1) grandfather existing long-term local resource adequacy commitments, and (2) credit LSE self-procurement of any preferred resources or energy storage that meet the local RA program's requirements, using a financial crediting mechanism proposed by CalCCA and detailed by Calpine.[5]

Whatever the Commission's approach, it must reject proposals by Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE") to make significant, complex and yet-unexplored changes to the central procurement model.

II. REPLY TO PG&E/SCE COMMENTS

A. Reclassifying PCIA Resources as CAM Resources Is Unnecessary and Introduces Complexities and Questions Not Addressed in the Record

PG&E/SCE propose that IOU resources procured by the CPE should be "reclassified" from the Power Charge Indifference Adjustment ("PCIA") to "the CAM for the duration of the contract/multi-year obligation with the CPE."[6] Their proposal has not been explored in the record, lacks clarity, would modify existing PCIA vintages and, therefore, must be rejected.

In addition, there is no need for such reclassification. If the Commission adopts the PD, ignoring the many problems it engenders, PCIA resource sales to the CPE should be treated as any other resource sale by an IOU. The resources and their costs should remain in the PCIA, and revenues received from the resource adequacy ("RA") sale to the CPE should be treated as an offset to PCIA costs and a credit in customer rates. This would ensure the best value for retail customer during a time of increasing economic uncertainty and rising electric costs. In effect, the costs of attributes provided to the CPE will be recovered through the mechanism specified in the decision and the costs of other attributes or above-market costs will be recovered through the PCIA. No special "reclassification" of resources is required.

B. Removing the Requirement for the IOU to Bid Its PCIA Resources into the CPE Unlawfully Shifts Costs from Bundled Customers to CCA and DA Customers

PG&E/SCE and the California Large Electricity Consumers Association ("CLECA") propose to permit an IOU to exercise its discretion to withhold its resources from the CPE on grounds that the IOU

---

5 Calpine Comments at 8. A clarifying change to the PD is provided in Appendix B.

6 PG&E/SCE Comments at 13.

should not be treated differently from other LSEs who maintain this discretion.[7] CLECA argues that IOUs should have the right to maintain resources to meet their own system and flexible RA needs. CLECA correctly points out that "[i]f a local RA resource is accepted through the CPE RFO process, then all of its attributes, including system and flexible capacity, are allocated to other LSEs."

CLECA identifies one of the significant flaws in the PD's model: to convey local RA value to the CPE, a seller must give up all RA attributes. But giving IOUs discretion whether to bid their resources in the CPE solicitation does not fairly resolve the problem. IOUs should not have the same discretion as other LSEs because they ***are not like*** other LSEs. The resources that will be bid are held by the IOUs in the PCIA portfolio were procured for and are operated for the benefit of ***all customers*** who pay the PCIA – bundled and departed. Indeed, this is the fundamental principle underlying departing load customers' obligations to pay the PCIA. It is thus unreasonable to allow the IOUs to withhold needed local RA from the market to satisfy bundled customers' system and flexible RA needs and deny the availability of these resources to other LSEs and their customers who already pay for them. This approach shifts costs from bundled customers to CCA - an outcome that would violate §454.52(c).

The solution for the problem the IOUs and CLECA identify is not to allow IOUs to withhold their resources, but to limit the scope of the CPE's procurement to local RA while maintaining the requirement that the IOUs offer all local resources to the CPE. The IOUs' system and flexible RA attributes could then be allocated to LSEs through the PCIA Working Group 3 solution. Attempting to solve it by enabling IOU withholding local RA capacity from the market risks higher costs and reduced resource availability for departing load customers solely for the benefit of bundled customers.

III. REPLY TO CAL ADVOCATES AND TURN

A. Grandfathering of Existing Contracts Is Critical to Address the Need for Adequate Notice of Rule Changes and to Prevent Potential Stranded of Existing Investments

The PD calls for a working group to address consequences of its model for existing, longer term local RA contracts.[8] Cal Advocates questions why existing contracts need to be addressed, since the resources could be sold into the CPE.[9] TURN also questions the vagueness of the PD's approach, but points to the need to "quickly" be clear about grandfathering "to help minimize LSE's uncertainties about continuing with local investments that are now being developed."[10] TURN's approach is correct.

---

7 PG&E/SCE Comments at 11-12; CLECA Comments at 5.
8 PD at 35.
9 Cal Advocates Comments at 3.
10 TURN Comments at 3.

The Commission previously recognized the need to grandfather existing contracts in the face of a significant RA rule change to ensure fair notice has been provided and prevent stranding existing investments.[11] If the Commission adopts the PD without providing a crediting mechanism for all shown local resources, it must likewise expressly provide for grandfathering of existing agreements. As TURN suggests, these LSEs should be credited for their share of local requirements, and CalCCA recommends providing this credit through the financial crediting mechanism outlined in CalCCA's opening comments.[12] The Commission should direct grandfathering; no workshop is required.

B. Allocating GHG Emissions for Resources Procured by the CPE Is Unsupported by the Record, Runs Counter to CEC Regulations and Exacerbates the PD's Departure from Statute

Cal Advocates contends that LSEs should "properly and transparently report their responsibility for GHG emissions associated with procurement that the CPE conducts <u>on their behalf</u>," proposing resolution of this issue in R.19-11-009 as "soon as possible."[13] CalCCA agrees that there is no record in this proceeding that would support Cal Advocates' proposal. Moreover, the proposal is contrary to the resolution of this issue by the Energy Commission.[14]

The proposal, however, brings into focus the consequences of the PD's removal of self-procurement autonomy from the hands of local governments and the millions of customers they serve. Many local governments have elected to pursue and are meeting more aggressive greenhouse gas reduction targets than the IOUs have themselves pursued. Placing a material portion of the RA procurement market in the hands of the CPE undermines these goals, enabling the CPE to procure GHG-emitting resources rather than meeting reliability requirements with preferred resources, and then allocating these GHG emissions to local governments. In other words, the PD's violation of Public Utilities Code §380(b)(5) and (h)(5) – which direct the Commission to "maximize" CCA procurement autonomy – has real consequences for the pace at which the state will achieve its climate goals. It further violates Section 454.52(b)(3), which requires the local government to approve the resources used to serve a CCA's customers. Forcing an allocation of GHG emissions from the CPE's, rather than LSE's, choice of resource exacerbates the injury to local governments, and represents a lost opportunity for the state to accelerate progress toward international GHG reduction targets.

---

11 *See* D.05-10-042 at 63-65.

12 CalCCA Comments at 13-14; *see also* Calpine Comments at 8.

13 Cal Advocates Comments at 6.

14 *See* Docket No. 16-OIR-05, Resolution Adopting Regulations, Dec. 17, 2019, §1393(a)(5).

IV. LSES ARE INVESTING IN LOCAL RESOURCE PROCUREMENT

OhmConnect correctly calls out the PD's "misleading" and unsupported statements ignoring the local preferred resource procurement undertaken by LSEs.[15] Last week, for example, Clean Power Alliance announced a 100 MW/400 MWh battery storage project in the Big Creek/Ventura local area.[16] Likewise, East Bay Community Energy has partnered with PG&E on the Oakland Clean Energy Initiative – a 43.75 MW battery energy storage project coupled with renewable resources.[17] In all, CCAs have entered into contracts with 29 new preferred resource and energy storage facilities in constrained local areas, representing 1,642MW of nameplate capacity to be online by 2022, as shown in Appendix A. Regulatory certainty is paramount to continuing this trend toward adding cost effective, low carbon capacity to meet local, state and international goals.

V. CONCLUSION

For all the foregoing reasons, the Commission should modify the proposed decision as recommended by CalCCA and reject the proposals of PG&E/SCE identified in these reply comments.

April 20, 2020

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel

---

15 OhmConnect Comments at 2 (*citing* PD at 25).

16 https://cleanpoweralliance.org/2020/04/09/clean-power-alliance-signs-large-scale-100mw-battery-energy-storage-agreement/

17 *See* Application of Pacific Gas and Electric Company for Approval and Recovery of Oakland Clean Energy Initiative Preferred Portfolio Procurement Costs, Apr. 15, 2020, at 3-4.

APPENDIX A

Table 1: New Build CCA-Contracted Capacity in Constrained Local Areas, COD 2013-2022

	Big Creek / Ventura	LA Basin	Greater Bay Area	PG&E Other	San Diego / Imperial Valley	Total
Projects	6	1	5	16	1	**29**
Solar Capacity (MW, Nameplate)	340.0		10.5	743.5	100.0	**1194.0**
Storage Capacity (MW, Nameplate)	195.0		43.8	110.3	10.0	**359.0**
Wind Capacity (MW, Nameplate)		22.0	57.5			**79.5**
Biogas Capacity (MW, Nameplate)				9.9		**9.9**
Total Capacity (MW, Nameplate)	**535.0**	**22.0**	**111.8**	**863.7**	**110.0**	**1642.4**

APPENDIX B

Additional Recommended Changes

Findings of Fact:

8. ~~A hybrid central procurement framework strikes~~ To strike a reasonable balance between the residual and full procurement models and ~~best addresses~~ ensure reasonable incentives for an LSE to develop preferred or energy storage resources in local areas, ~~the known challenges identified in the local RA market,~~ the central procurement model must (1) provide a financial crediting mechanism for LSEs who self-procure and show their preferred or energy storage resources to the CPE and for existing local RA resources (2) allocate costs based on the LSE cost-causation.

NEW. The financial credit for resources shown to the CPE shall be calculated as the average price paid in the relevant local area in the CPE's solicitation less the value of system RA and flexible RA price based on the most recent twelve months of data collected by the Energy Division from LSEs.

Ordering Paragraphs

4.a. If a load serving entity's (LSE) procured resource also meets a local Resource Adequacy (RA) need, the LSE may choose to: (1) show the resource ~~to reduce the central procurement entity's (CPE) overall local procurement obligation~~ and receive a direct financial credit for any preferred or energy storage resource shown or for existing local RA commitments, (2) bid the resource into the CPE's solicitation, or (3) elect not to show or bid the resource to the CPE and only use the resource to meet its own system and flexible RA needs.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009 (Filed on November 7, 2019)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION REPLY COMMENTS ON TRACK 2 PROPOSALS

Evelyn Kahl, General Counsel
California Community Choice Association
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
regulatory@cal-cca.org

April 2, 2020

Table of Contents

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009 (Filed on November 7, 2019)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REPLY COMMENTS ON TRACK 2 PROPOSALS

Pursuant to the February 28, 2020, *Administrative Law Judge's Ruling Modifying Track 2 Schedule*, and the March 6, 2020 *Email Ruling Granting Extension to File Track 2 Reply Comments*, the California Community Choice Association ("CalCCA")[1] respectfully submits these reply comments on the Track 2 Resource Adequacy ("RA") proposals submitted by the Energy Division Staff ("Staff") and other parties on February 21, 2020, to address issues raised in the *Assigned Commissioner's Scoping Memo and Ruling.*[2]

I. INTRODUCTION AND SUMMARY

CalCCA appreciates the opportunity to offer reply comments in response to opening comments by the California Independent System Operator ("CAISO"), Southern California Edison Company ("SCE"), Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), the Public Advocates Office ("Cal Advocates"), the Alliance for

---

1 California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

2 *Assigned Commissioner's Scoping Memo and Ruling*, Jan. 22, 2020 ("Scoping Memo").

Retail Energy Marketing ("AReM"), the Joint Environmental Parties, the Solar Energy Industry Association and Large Scale Solar Association ("SEIA/LSA"), Western Power Trading Forum ("WPTF") and Calpine Corporation ("Calpine"). Responding to these parties, these comments urge the Commission to address Track 2 issues by:

- ✓ Adopting CalCCA's proposed system and flexible RA waiver process;
- ✓ Adopting SCE's hybrid Qualifying Capacity ("QC") counting proposal for hybrid resources limited by Investment Tax Credit ("ITC") charging restrictions for 2021-2024, revisiting its suitability thereafter as more experience is gained with these resources;
- ✓ Transitioning from an average to a marginal Effective Load Carrying Capability ("ELCC") methodology for solar and wind resources accounting for further technology differentiation;
- ✓ Clarifying and further refining the Staff proposal for Maximum Cumulative Capacity ("MCC") buckets prior to taking action;
- ✓ Adopting a positive incentive for LSEs to fill deficiencies between the Year-Ahead and Month-Ahead filings by retroactively lowering the penalty amount; and
- ✓ Focusing escalation of non-compliance consequences only on LSEs that repeatedly fail to take commercially reasonable efforts to procure their RA requirements.

CalCCA requests that the Commission adopt these proposals, along with other proposals advanced in CalCCA's opening comments, in framing an approach to Track 2 issues.

II. ADOPT A SYSTEM/FLEXIBLE RA WAIVER PROCESS

CalCCA submitted a late-filed proposal for a system/flexible waiver process, reiterating the request made in the *California Community Choice Association Petition for Modification of Decision 19-06-026*, filed on October 30, 2019 ("Petition"). CalCCA appreciates the statement from Shell in its Opening Comments that the CPUC should consider a waiver process that applies to any LSE that is unable to meet its obligations due to market and availability-related reasons. CalCCA also appreciates the responses of WPTF and Calpine and addresses their concerns regarding process and the interpretation of "commercially reasonable" in the context of prices and compliance efforts.

As an initial matter, WPTF raises concerns that CalCCA's proposal was not raised for discussion earlier in Track 2.[3] While further discussion may have been beneficial in the context of workshops, CalCCA expected that the Commission would in time address its Petition. In addition, SCE made the same proposal in 2019, and CalCCA's proposal has been pending since October 30, 2019, as noted above. CalCCA further observes that WPTF filed no opposition to CalCCA's original proposal in its Petition. Thus there is no justification for the Commission to reject the proposal on procedural grounds.

Both WPTF[4] and Calpine[5] argue that the proposal does not specifically define "commercially reasonable" in the context of prices and procurement efforts, and Calpine urges additional process to define this term. A definition is unnecessary for several reasons:

- ✓ "Commercially reasonable" is a well-understood legal term used frequently in industry and contracting.
- ✓ "Commercially reasonable efforts" is used in the context of the local RA waiver process with no explicit definition;[6] the CalCCA system and flex waiver proposal goes even a step further than this by specifying several actions an LSE must take.
- ✓ The local waiver process also requires the Staff to determine what are "reasonable terms and/or conditions."
- ✓ An explicit definition of "commercially reasonable price" could have the undesirable result of suppliers offering all resources at the defined price.

---

3 *Western Power Trading Forum Comments on Track 2 Proposals,* Mar. 23, 2020 ("WPTF Comments") at 3.

4 WPTF Comments at 4.

5 *Comments of Calpine Corporation on Track 2 Proposals*, Mar. 23, 2020 ("Calpine Comments") at 14-15.

6 D.06-06-064 at 73.

For these reasons, the Commission should not adopt a specific definition of a "commercially reasonable price."

Additionally, Calpine's concern regarding "commercially reasonable actions" is addressed in the Petition. CalCCA proposes that the commercially reasonable actions to obtain the needed RA resources include:[7]

- ✓ Documented, robust efforts to procure system RA through bilateral contracts;
- ✓ Participation in multiple utility or third-party solicitations; and
- ✓ The LSE's issuance of an RFO for RA products before August 31 of the year preceding the compliance year.

For this reason, CalCCA suggests that no further examination is required to interpret "commercially reasonable action" for purposes of the waiver proposal.

The Commission should adopt the framework proposed by CalCCA for system/flexible RA waivers. There is no dispute that the system RA market is tightening, and individual LSEs cannot address the scarcity until more resources are installed in response to the IRP procurement track directives.

III. ADOPT SCE'S HYBRID COUNTING PROPOSAL FOR ITC-LIMITED HYBRID RESOURCES

Hybrid resources will be an increasingly significant share of new resources coming online in the near- and mid-term planning horizon, in large part due to their increased reliability contributions relative to standalone solar and wind resources. CalCCA agrees with the CAISO,[8]

---

[7] CalCCA Petition at 8.

[8] *California Independent System Operator Corporation Consolidated Comments on All Workshops and Proposals*, Mar. 23, 2020 ("CAISO Comments") at 15.

PG&E,[9] Cal Advocates,[10] and other parties[11] that SCE's proposed methodology strikes an appropriate balance between the conservative interim methodology and the proposed additive methodology.

As noted by CAISO and other parties, this methodology may require revision as the industry gains greater understanding of the potential and limitations of hybrid resources. To facilitate market stability and promote much-needed near-term investment in flexible preferred resources, the Commission should adopt SCE's proposed counting methodology while indicating its expectations for the durability and longevity of this methodology. CalCCA proposes a three-year window, from 2021 through 2023, during which the hybrid methodology would remain unchanged and performance would be analyzed by stakeholders, with revisions to the methodology (if necessary) taking effect in 2024. This would align with the current tranche of new resource development directed by the procurement track in D. 19-11-016.

---

9 *Comments on Pacific Gas and Electric Company (U39 E) on Track 2 Proposals, March 5 Track 2 Workshop, and March 11 Working Group Reports* ("PG&E Comments") at 14 (supporting the SCE proposal as an interim methodology until data are available to establish an exceedance method).

10 *Comments of the Public Advocates Office on Track 2 Resource Adequacy Proposals* ("Cal Advocates Comments"), Mar. 23, 2020, at 8.

11 *Hybrid Counting Working Group Final Report* at 10.

IV. TRANSITION TO A MARGINAL APPLICATION OF ELCC FOR SOLAR AND WIND RESOURCES AND CONSIDER OTHER INTRA-TECHNOLOGY DIFFERENTIATION

SCE,[12] SDG&E,[13] AReM,[14] Calpine,[15] and the Joint Environmental Parties[16] generally support the transition to a marginal ELCC framework for solar and wind resources, with some parties also calling for differentiation by technology and geography within resource classes.[17] CalCCA agrees with these parties that a marginal ELCC valuation will send a better economic signal for new resource development and should be used not only within the IRP for planning purposes, but also for RA compliance purposes. As the CAISO[18] points out, however, an average ELCC factor may be necessary for some planning processes, such as the proposed portfolio assessment. In addition, as SDG&E[19] and Calpine[20] explain, to the extent aggregate RA value attributed through a marginal ELCC valuation substantively differs from the results of an average valuation, it may be necessary to revise the valuation to maintain the integrity of the RA program.

---

12 *Southern California Edison Company's (U 338-E) Comments on Workshop on Track 2 Proposals, Track 2 Proposals, and Track 2 Working Group* Reports, Mar. 23, 2020, at 15.

13 *San Diego Gas & Electric Company (U 902 E) Comments on Track 2 Proposals, Workshop and Working Group Reports*, Mar. 23, 2020 ("SDG&E Comments") at 15-18.

14 *Comments of the Alliance for Retail Energy Markets on Track 2 Proposals, Proposed Revisions to Maximum Cumulative Capacity Buckets, and Working Group Reports*, Mar. 23, 2020 ("AReM Comments"), at 13.

15 Calpine Comments at 4.

16 *Sierra Club, California Environmental Justice Alliance, and Union of Concerned Scientists Track 2 Comments*, Mar. 23, 2020 ("Joint Environmental Parties Comments"), at 4 (suggesting additional work "be done to develop marginal ELCC values").

17 *See, e.g.,* SCE Comments at 15.

18 CAISO Comments at 5-6.

19 SDG&E Comments at 17.

20 Calpine Comments at 5-6.

V. CLARIFY AND FURTHER REFINE THE MCC BUCKETS PROPOSAL PRIOR TO TAKING ACTION

Despite general support for Staff's proposed Option 4B, numerous parties seek clarification on important details of the MCC proposals, signaling uncertainty regarding the application of the proposal to different resource technologies and categories. Further, several parties comment on the structural significance of the MCC bucket proposal in the context of the broader efforts to realign the RA program to address the increasing role of preferred resources. To the extent the Commission intends to make further structural refinements of the RA program related to preferred resource integration in Track 3 or Track 4 of this proceeding, CalCCA agrees with SEIA-LSA,[21] the Joint Environmental Parties,[22] and others that it would be better to take such action as part of a broader structural change within those later tracks than to make piecemeal changes within each track.

VI. ADOPT A POSITIVE INCENTIVE FOR LSES TO FILL DEFICIENCIES BETWEEN YEAR-AHEAD AND MONTH-AHEAD FILINGS BY RETROACTIVELY LOWERING THE PENALTY AMOUNT

In opening comments, Calpine,[23] AReM,[24] and CalCCA[25] all proposed that the CPUC should incentivize LSEs to fill deficiencies between the Year-Ahead and Month-Ahead filings by retroactively lowering the penalty amount for deficiencies successfully filled. SCE[26] and Shell[27] also opposed the imposition of a redundant Month-Ahead penalty for deficiencies already

---

[21] *Comments of the Solar Energy Industries Association and the Large-Scale Solar Association on Track 2 Issues Concerning the Commission's Resource Adequacy Program*, Mar. 23, 2020, at 14-15.

[22] Joint Environmental Parties Comments at 5-6.

[23] Calpine Comments at 14.

[24] AReM Comments at 6-7

[25] CalCCA Comments at 19-20.

[26] SCE Comments at 21-22.

[27] *Opening Comments of Shell Energy North America (US), L.P. on Track Two Proposals,* Mar. 23, 2020, at 3-4.

penalized in the Year-Ahead. Specifically, AReM proposed that LSEs who cure a Year-Ahead deficiency before the Month-Ahead filing should be returned 50 percent of the deficiency penalty.[28] CalCCA supports AReM's proposal and urges the Commission to adopt a positive incentive to cure deficiencies between the Year-Ahead and Month-Ahead filings, rather than a redundant penalty that will unnecessarily harm ratepayers.

VII. FOCUS ESCALATION OF NON-COMPLIANCE CONSEQUENCES ONLY ON LSES THAT CONSISTENTLY FAIL TO TAKE COMMERCIALLY REASONABLE EFFORTS TO PROCURE RA

CalCCA agrees with SCE[29] and PG&E[30] that further exploration of consequences for non-compliant LSEs warrants additional exploration. CalCCA also supports Cal Advocates' direction toward making transparent the identities of non-compliant LSEs, the efforts they undertook to procure, and the categories of non-compliance.[31] Greater transparency will facilitate better understanding of the drivers behind non-compliance and will support the development of a framework for assessing the intent and efforts of non-compliant LSEs. A system and flexible RA waiver process, as proposed by CalCCA,[32] will support this direction, enabling the Commission to differentiate non-compliance as an intentional procurement strategy from non-compliance resulting from market shortages.

CalCCA further agrees with AReM that expeditious resolution of the PCIA Working Group 3 proposal on Portfolio Optimization will better rationalize RA compliance among LSEs. The allocation and market offer proposals included in the Power Charge Indifference Adjustment

---

28 AReM Comments at 6.
29 SCE Comments at 20.
30 PG&E Comments at 7.
31 Cal Advocates Comments at 29
32 *See supra* Section VI.

Working Group 3[33] will ensure that IOUs, CCAs, and ESPs have equal access to the RA resources procured by the IOU on behalf of their customers.

Finally, CalCCA agrees with SCE[34] that increasing penalties may have the unintended effect of increasing the potential for market power exercise in light of market scarcity. CalCCA's proposal for a system and flexible RA waiver, combined with escalating penalties for repeated noncompliance, will ensure that higher penalties directly address non-compliance without increasing costs for the customers of LSEs making every effort to comply.

VIII. CONCLUSION

CalCCA requests adoption of the proposals advanced in its opening and reply comments, including:

- ✓ Adopting CalCCA's proposed system and flexible RA waiver process;
- ✓ Adopting SCE's hybrid QC counting proposal for hybrid resources limited by ITC charging restrictions for 2021-2024, revisiting its suitability thereafter as more experience is gained with these resources;
- ✓ Transiting from an average to a marginal ELCC methodology for solar and wind resources accounting for further technology differentiation;
- ✓ Clarifying and further refining the Staff proposal for MCC buckets;
- ✓ Adopting a positive incentive for LSEs to cure deficiencies between the Year-Ahead and Month-Ahead filings by retroactively lowering the penalty amount; and

33 *See generally* R.17-06-026, *Final Report of Working Group 3 Co-Chairs*, Feb. 21, 2020.

34 SCE Comments at 20.

- ✓ Focusing escalation of non-compliance consequences only on LSEs that repeatedly fail to take commercially reasonable efforts to procure their RA requirements.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

April 2, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 18-07-003 (Filed July 23, 2018)

INFORMAL REPLY COMMENTS OF THE JOINT CCA PARTIES ON RENEWABLES PORTFOLIO STANDARD WORKSHOP ON PROCUREMENT PLAN AND COMPLIANCE REPORT TEMPLATES

Justin Wynne
Braun Blaising Smith Wynne, P.C.
555 Capitol Mall, Suite 570
Sacramento, CA 95814
(916) 326-5812
wynne@braunlegal.com

Counsel for the Cities of Lancaster, Pico Rivera, San Jacinto, and Rancho Mirage

And on behalf of Apple Valley Choice Energy, Clean Power Alliance, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority

(collectively, "Joint CCA Parties")

Dated: April 2, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 18-07-003 (Filed July 23, 2018)

INFORMAL REPLY COMMENTS OF THE JOINT CCA PARTIES ON RENEWABLES PORTFOLIO STANDARD WORKSHOP ON PROCUREMENT PLAN AND COMPLIANCE REPORT TEMPLATES

I. INTRODUCTION

The Joint CCA Parties submit the following informal reply comments on the *Renewables Portfolio Standard Workshop on Procurement Plan and Compliance Report Templates*, held on February 27, 2020. On March 19, 2020, parties filed informal comments on the February 27 workshop and on a list of questions released by the California Public Utilities Commission's ("Commission") Energy Division.[1]

II. REPLY COMMENTS

The Joint CCA Parties generally support the various party comments that recommend changes that would reduce the redundancy and administrative burdens associated with the Renewables Portfolio Standard ("RPS") program reporting requirements. However, the Joint

[1] The following parties filed opening informal comments on March 19: the Alliance for Retail Energy Markets ("AReM") and the Regents of the University of California ("UC"), in its role as an Electric Service Provider (collectively "AReM/UC Comments"); CleanPowerSF; Southern California Edison Company ("SCE"), Pacific Gas and Electric Company ("PG&E"), and San Diego Gas & Electric Company ("SDG&E") (collectively, the "Joint IOUs"); Shell Energy North America (US), L.P. ("Shell Energy"); Bear Valley Electric Service ("BVES"), a division of Golden State Water Company, Liberty Utilities (CalPeco Electric) LLC ("Liberty CalPeco"), and PacifiCorp , d.b.a. Pacific Power ("PacifiCorp") (collectively, the California Association of Small and Multi-Jurisdictional Utilities ("CASMU")); and the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates").

CCA Parties urge the Commission to seek additional input from the parties before making any major changes to the templates or reporting requirements, such as combining or eliminating any specific forms or adopting new reporting requirements. This section provides the Joint CCA Parties' responses to specific party proposals.

A. The Joint CCA Parties Oppose the Joint IOUs' Recommendation to Require All Retail Sellers to File Quarterly Project Development Status Reports.

The Joint IOUs recommend making the investor owned utility ("IOU") monthly Project Development Status Report ("PDSR") due on a quarterly basis.[2] The Joint IOUs also recommend making this new quarterly PDSR a requirement for all retail sellers, including electric service providers ("ESPs") and community choice aggregators ("CCAs").[3] The Joint CCA Parties take no position regarding the Joint IOUs' proposal to make the PDSR quarterly rather than monthly for IOUs. However, the Joint CCA Parties oppose the Joint IOUs' proposal to require all retail sellers to submit a quarterly PDSR. There is already a significant burden associated with existing reporting requirements applicable to CCAs. In light of this burden, the Commission should use caution when considering creating a new reporting mandate, particularly where the information is not necessary for determining compliance with any specific requirement.

The Joint CCA Parties urge Commission staff to first clearly identify the exact information that is needed and the specific purpose that this information serves. Next, Commission staff should determine if this information is already provided to the Commission through filings submitted in another proceeding, such as the integrated resource plan proceeding or reporting for the power charge indifference adjustment ("PCIA"). If this information is

---

[2] Joint IOU Comments at 3.
[3] *Id.*

necessary for a clear Commission purpose, and is not already provided in some other way, the Commission staff should work with the parties to identify the best method for providing this information. Rather than a mandatory regular filing, this could take form of a periodic data request or as a modification to an existing reporting requirement. Until Commission staff has made these determinations, it would be premature to act on the Joint IOUs' recommendation and adopt a new reporting requirement. The Commission should defer acting on this recommendation and seek more input from the parties.

B. The Joint CCA Parties Generally Support the Joint IOUs' Proposal for Energy Division to Provide a Template by June 1st Each Year and to Not Make Any Revisions to the Template Once It Has Been Provided.

The Joint IOUs recommend that Energy Division provide the finalized annual RPS Compliance Report template to retail sellers by June 1st each year.[4] The Joint IOUs also recommend that once the template is released, that Commission staff make no further changes to the template. The Joint CCA Parties generally support both of these recommendations as reasonable goals for Energy Division. Providing at least two months of time for retail sellers to complete the annual RPS Compliance Reports should be sufficient in most circumstances. Further, issuing corrected forms after parties have already started completing the prior version results in wasted time and effort associated with starting the process over, and should be avoided. To support both of these goals, Energy Division should work to release draft template forms well in advance of this June 1st deadline so that the retail sellers can help identify any errors or areas of confusion. Further, to the extent a major error is discovered after June 1st, Energy Division should seek a solution that does not involve requesting the retail sellers to start over with new

[4] *Id.* at 4.

forms. However, if new forms are distributed, Energy Division should extend the deadline for submitting forms by a period of time that recognizes the impact of such an action.

C. The Joint CCA Parties Support Incorporating the Static Contract Template into the "Contract Details" Tab of the RPS Compliance Report.

In opening comments, numerous parties identified potential redundancies that could be eliminated to reduce the reporting burdens associated with the RPS Procurement Plans and RPS Compliance Reports. The AReM/UC Comments,[5] Shell Comments,[6] and CASMU Comments[7] all identified a clear example and recommend incorporating the Static Contract Template into the "Contract Details" tab of the RPS Compliance Report. The Joint CCA Parties support this recommendation as an obvious way to eliminate an unnecessary form. It appears that there is substantial overlap between these two documents and that any information that is only contained in the Static Contract template could simply be added to the "Contract Details" tab.

III. CONCLUSION

The Joint CCA Parties appreciate the opportunity to provide these informal reply comments to the Commission.

April 2, 2020

Respectfully submitted,

/s/ Justin Wynne

Justin Wynne
Braun Blaising Smith Wynne, P.C.
555 Capitol Mall, Suite 570
Sacramento, California 95814
(916) 326-5812
wynne@braunlegal.com

[5] AReM/UC Comments at 2.
[6] Shell Comments at 3.
[7] CASMU Comments at 5-6.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions.	Rulemaking 18-12-005 (Filed December 13, 2018)

REPLY TO RESPONSES TO JOINT MOTION FOR EMERGENCY ORDER REGARDING DE-ENERGIZATION PROTOCOLS DURING THE COVID-19 PANDEMIC

LAW OFFICES OF MEGAN M. MYERS
Megan M. Myers
110 Oxford Street
San Francisco, California 94134
Telephone: (415) 994-1616
Email: meganmmyers@yahoo.com

Attorneys for California State Association of Counties

CENTER FOR ACCESSIBLE TECHNOLOGY
Melissa W. Kasnitz
3075 Adeline Street, Suite 220
Berkeley, California 94703
Telephone: (510) 841-3224
Email: service@cforat.org

Attorneys for Center for Accessible Technology

CITY OF SAN JOSE
Richard Doyle, City Attorney
Yue-Han Chow, Senior Deputy City Attorney
Luisa Elkins, Senior Deputy City Attorney
Office of the City Attorney
200 East Santa Clara Street, 16th Floor
San Jose, California 95113-1905
Telephone: (408) 535-1201
Email: Yue-Han.Chow@sanjoseca.gov
Luisa.Elkins@sanjoseca.gov

Attorneys for City of San Jose

COUNTY OF SANTA CLARA
James R. Williams, County Counsel
Tiffany M. Lin, Deputy County Counsel
70 W. Hedding Street, Fl. 9
San Jose, California 95110
Telephone: (408) 299-5900
Email: tiffany.m.lin@cco.sccgov.org

Attorneys for County of Santa Clara

GOODIN, MACBRIDE,
SQUERI & DAY, LLP
Megan Somogyi
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
Email: msomogyi@goodinmacbride.com

Attorneys for Counties of Kern, Marin, Mendocino, Napa, Nevada, San Luis Obispo, Santa Barbara, and Sonoma, and the City of Santa Rosa

EAST BAY COMMUNITY ENERGY
Melissa Brandt, Senior Director of Public Policy and Deputy General Counsel
1999 Harrison Street, Suite 800
Oakland, California 94612
Telephone: (510) 570-5110
Email: mbrandt@ebce.org

Attorneys for East Bay Community Energy

MARIN CLEAN ENERGY
Stephanie Chen, Senior Policy Counsel
1125 Tamalpais Avenue
San Rafael, California 94901
Telephone: (415) 464-6664
Email: schen@mcecleanenergy.org

Attorneys for Marin Clean Energy

BRAUN BLAISING SMITH WYNNE, P.C.
David Peffer
555 Capitol Mall, Suite 570
Sacramento, California 95814
Telephone: (916) 326-5812
Email: peffer@braunlegal.com

Attorneys for Marin Clean Energy and Peninsula Clean Energy

PIONEER COMMUNITY ENERGY
Jenine Windeshausen, Executive Director
2510 Warrant Drive, Suite B
Rocklin, California 95677
Telephone: (279) 999-7011
Email:
regulatory@PioneerCommunityEnergy.ca.gov

Representatives for Pioneer Community Energy

RURAL COUNTY REPRESENTATIVES OF CALIFORNIA
Staci Heaton, Senior Regulatory Affairs Advocate
John Kennedy, Legislative Advocate
1215 K Street, Suite 1650
Sacramento, California
Telephone: (916) 447-4806
Email: sheaton@rcrcnet.org
jkennedy@rcrcnet.org

Advocates for Rural County Representatives of California

Dated: April 24, 2020

TABLE OF CONTENTS

Page

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions.	Rulemaking 18-12-005 (Filed December 13, 2018)

REPLY TO RESPONSES TO JOINT MOTION FOR EMERGENCY ORDER REGARDING DE-ENERGIZATION PROTOCOLS DURING THE COVID-19 PANDEMIC

In accordance with Rule 11.1 of the Commission's Rules of Practice and Procedure, and Administrative Law Judge Brian Stevens' April 15, 2020 email ruling setting the deadlines for responses to the joint motion and replies to the responses, the California State Association of Counties (CSAC), the Center for Accessible Technology (CforAT), the City of San Jose, the County of Santa Clara, East Bay Community Energy, the Joint Local Governments (the Counties of Kern, Marin, Mendocino, Napa, Nevada, San Luis Obispo, Santa Barbara, and Sonoma, and the City of Santa Rosa), Marin Clean Energy, Peninsula Clean Energy, Pioneer Community Energy, and the Rural County Representatives of California (RCRC) (together the Moving Parties) submit this reply to the responses to the joint motion for an emergency order adopting de-energization regulations for the COVID-19 pandemic. The Moving Parties appreciate the prompt schedule set by the Commission for review of the motion, as well as the responding parties' recognition of the serious public safety issues related to de-energization during the COVID-19 pandemic, the utility pledges to work more closely with public safety partners to ensure local needs are met and the public is protected, and the recommendations for clarifications and refinements of the proposed regulations.

I. INTRODUCTION

The proposed regulations put forward by the Moving Parties are, first and foremost, about protecting the public. The best way to protect the public from the dual hazards of COVID-19 and de-energization is first to ensure that any contemplation of a de-energization event carefully considers all risks, both of turning the power off and of keeping the power on. In addition to such careful consideration in order to minimize the number of de-energization events that take place this upcoming fire season, public safety is best served by requiring rigorous coordination between the utilities and the local governments who are on the front lines of both the COVID-19 pandemic and de-energization events and by taking additional steps to ensure that affected members of the public, and particularly the most physically and financially vulnerable individuals, are protected from the harms that result from both.

The coordination envisioned by the proposed regulations goes beyond the coordination that the large utilities, with varying degrees of success, historically or currently offer to their local governments, but it is the level of coordination necessary to effectively manage a de-energization event in this time of pandemic. The intensity of the pre-fire season planning in the proposed regulations—the inventories of hospitals and medical treatment facilities, the cataloguing of critical facilities' backup power capabilities, the planning for ways to keep those facilities energized, the identification of critical businesses necessary for societal continuity, the analysis of how shutting off the power is likely to impact the affected communities—is the baseline of what needs to be done before the utilities can responsibly shut off the power while an emergency declaration or stay-at-home order is in place. Any effort by the utilities to draw lines in the sand regarding responsibility, and to use those divisions of responsibilities as a reason to not fully prepare for de-energization events or understand the ramifications of shutting off the power, will not protect the public.

The utilities point to their authority to control de-energization decisions and the existing de-energization rules as reasons the proposed regulations are unworkable and unnecessary. To the contrary, the existing de-energization program and the breadth of utility control over de-energization events support the proposed regulations. The Commission has mandated that the utilities analyze the public safety ramifications of shutting off the power,[1] mandated close coordination between the utilities and local governments,[2] and mandated that the utilities provide assistance and mitigation to critical facilities and customers.[3] The coordination, planning, and mitigation ordered by the Commission, at the level of intensity described in the proposed emergency guidelines, is necessary precisely *because* the utilities control the ultimate decisionmaking, the logistics, and the information related to de-energization events. As SDG&E asserted, the utilities are the only entities that possess the knowledge and experience to operate their electric systems, as well as the situational awareness tools and experience to make de-energization decisions.[4] De-energization events are not like other disasters; they are controlled by a single entity that has total visibility into the factors dictating the size and duration of the event.

But the ability to decide whether, when, and how to shut off the power carries an awesome responsibility. When making that decision, the utilities have an obligation to understand the conditions on the ground in the impacted communities, to have coordinated extensively with local governments and state agencies to ensure that there is a coherent plan and everyone is on the same page, to provide the best and most accurate information to public safety

[1] Resolution ESRB-8; D.19-05-042, pp. A22–A24 (Reporting requirement #7: "An explanation of how the utility determined that the benefit of de-energization outweighed potential public safety risks."); D.12-04-024.
[2] Resolution ESRB-8, pp. 5–7; D.19-05-042, pp. A2, A13, A19–A21, A25.
[3] See Resolution ESRB-8, p. 7; D.19-05-042, pp. A11–A12.
[4] SDG&E Response, p. 2.

partners and the public, to ensure that every option for leaving the power on has been exhausted, to truly understand the ramifications of the decision, and to ensure that the most vulnerable members of the public have access to the resources and information they need to mitigate the impacts of the de-energization event. If the utilities do not do, and know, and provide all these things, de-energization events are just ill-considered exercises in avoiding liability. To date, the large utilities' de-energization events have not displayed the required level of rigor before, during, or afterward. Now, with the overlapping emergency of COVID-19 impacting every aspect of our society, including actions taken to reduce the risk of catastrophic wildfire, more is needed.

The fact that the Moving Parties are making this request against the backdrop of existing de-energization regulations that promote consideration of public safety, coordination and communication with local governments, and the obligation to provide resources and mitigation to Access and Functional Needs (AFN) individuals, is significant. The Moving Parties believe that the Commission has heard the concerns of local governments and AFN populations and has, to a large extent, adopted de-energization regulations designed to address those concerns. But the large utilities—PG&E in particular, and SCE and SDG&E to a lesser extent—have failed to fully implement those regulations. Moreover, between receiving authority in mid-2018 to de-energize their systems and the de-energization events of late 2019, PG&E and SCE did not design their programs to include the necessary level of analysis regarding public safety, coordination with local governments, adequate resources and information for AFN individuals, robust alternatives to shutting off the power, or metrics for analyzing the potential harms from de-energization compared to the likely benefits. The resulting chaos, confusion, and hardship of the 2019 de-energization events was both predictable and predicted by the local governments, AFN advocates, and individuals who bore the brunt of these events. The improvements the utilities have made in the wake of the 2019 events have brought their de-energization programs closer to the level they should have been at this time last year, but they are not yet at the level necessary to successfully de-energize in 2020, particularly in the midst of a pandemic.

Notwithstanding that fact, the utilities' efforts and improvements should be acknowledged. Their refinements to their situational awareness capabilities, increased system hardening and vegetation management, expanded efforts to provide Community Resource Centers and other mitigations to impacted residents, and increased communication with local governments are important and are yielding some good results. The utilities have expended significant time and resources to undertake these improvements. The Moving Parties also appreciate SCE's thoughtful response that outlines the utility's plans to incorporate COVID-19 considerations into its de-energization activities and to increase its coordination with local governments and other stakeholders.[5] Willingness to acknowledge that there is room for improvement and that the best results will be achieved through close coordination with government entities is crucial at this juncture, and is otherwise in short supply in the utilities' responses.

But the fact remains that the utilities' de-energization programs are not yet at the level they need to be to effectively manage de-energization events during the COVID-19 pandemic. The proposed emergency regulations are designed to promote the analysis, coordination, communication, information-sharing, and mitigations necessary to safely de-energize in 2020. The Moving Parties request that the Commission adopt the proposed emergency regulations, as modified below.

[5] SCE Response, pp. 10–16.

II. REVISIONS TO PROPOSED EMERGENCY PSPS/COVID-19 REGULATIONS

The Moving Parties appreciate the concerns raised by the responding parties regarding the proposed emergency regulations' implementation and logistics, and the recommendations for clarifications and revisions.[6] Based on the responses to the joint motion, the Moving Parties incorporate the following clarifications and logistical adjustments into the proposed regulations. The proposed revisions do not alter the purpose or intent of the regulations as originally proposed. A thorough discussion of each of the regulations is set forth in Section III.B below.

1. Prior to implementing a de-energization event, a utility must coordinate with local emergency managers within the potential outage footprint, CalOES, Cal FIRE, and the Commission's Safety and Enforcement Division to provide the utility's assessment of ~~evaluate~~ the need for de-energization and ~~to~~ the utility's assessment of the potential impacts, and to consider any local conditions related to COVID-19, as reported by the state or local entities, that may be relevant to the utility's assessment of the potential impacts of or the need for de-energization to protect public safety. Any decision to de-energize made by the utility following this consultation would not preclude the exercise of any legal rights or remedies available to the Commission or members of the public to hold utilities responsible for actions taken during the implementation of the de-

[6] Responses were submitted by: AT&T California; the California Association of Small and Multi-Jurisdictional Utilities (CASMU); the California Cable & Telecommunications Association (CCTA); the Coalition of California Utility Employees (CUE); Consolidated Communications of California Company (Consolidated); CTIA; Mussey Grade Road Alliance (MGRA); PG&E; SCE; SDG&E; the Small Business Utility Advocates (SBUA); the Small LECs; the Public Advocates Office; TURN; and the Utility Consumers' Action Network.

energization event, including denial of cost recovery, and would not preclude the Commission's after-the-fact assessment of the reasonableness of the de-energization event, or relieve the utilities of the responsibility to comply with the de-energization regulations set forth in Resolution ESRB-8, D.19-05-042, or any subsequent Commission order, during implementation of the de-energization event.

2. The utilities may not de-energize any line, circuit, or substation serving any city, county, tribe, or community with a shelter-in-place order due to COVID-19, without providing to the local and state entities listed in (1) above quantitative and qualitative analysis of the risk of utility-caused ignition from the impending weather event and the harms that are likely to result from de-energization. As part of that analysis, the utilities must consider factors including, but not limited to:

    a. The number of licensed bed counts for hospital beds and skilled nursing facilities in facilities located in the de-energization footprint, as published by the California Department of Public Health; ~~hospitalized COVID-19 patients in the de-energization footprint, as reported by state or local health departments;~~

    b. The number of reported cases of COVID-19 in the de-energization footprint, ~~as~~ to the extent reported by state or local health departments, ~~and~~ any available demographic breakdowns (e.g., age groups of patients), and any relevant patient-related information, such as hospital surge capacity, reported by state or local government entities;

c. The number of AFN individuals in the de-energization footprint, including customers enrolled in the utilities' medical baseline program, customers who were identified as ineligible for transition to default TOU based on the identification of a household member as having a chronic illness or other medical condition, customers who receive bills or other notices from the utility in alternative formats or languages other than English, customers who have otherwise self-identified as having a disability, and customers enrolled in CARE, FERA, and any other income-assistance programs;

d. The number and type of critical facilities in the de-energization footprint, and the known or likely results of de-energizing those facilities (e.g., loss of ability to process wastewater, loss of internet or phone service, hospitals' inability to perform medical procedures, compromised safety at correctional facilities, loss of bulk refrigeration capacity for warehouses and grocery stores, pharmacy closures, etc.);

e. The wind speed-related failure thresholds of the transmission lines and distribution circuits that are likely to be affected by the high-wind event, potentially necessitating de-energization ~~in the outage footprin~~t;

f. Up-to-date weather modeling showing areas of highest actual or predicted wind speeds;

g. The status of vegetation management work completed along the transmission lines and distribution circuits that are under consideration for de-energization;

h. An explanation of the options for keeping potentially impacted infrastructure energized, including sectionalization, temporary portable generation, redirecting power, and real-time observation;

i. The available personnel and resources that can be put in the field to monitor real-time conditions on potentially impacted transmission lines and distribution circuits;

j. The estimated individual and community financial losses, including spoiled food and medication, lost revenue by small businesses that cannot operate without power, lost wages by the employees of those small businesses, and other similar monetary harms based on damage claims submitted to the utilities ~~made~~ following the de-energization events of 2019; and

k. The estimated increased medical risk to the affected population, including the AFN population, including risk of harm due to nonfunctioning medical devices, increased risk of poor health outcomes due to lost medication, risk of harm due to lost ability to manage indoor temperature, increased response time for emergency calls due to demands on the emergency response system, and other similar medical risks based on information learned during the 2019 de-energization events.

3. Local governments, through the Operational Area, will have the ability to request and receive an exemption on a per-event basis from de-energization, in accordance with existing regulations for public safety partner requests for de-energization delay and for re-energization, if their public safety capabilities have been degraded by COVID-19 such that a PSPS event would exceed the local capacity to respond to the consequences of a shutoff. To obtain such an exemption, the local government will submit to the utility, and the Commission's Director of Safety and Enforcement on an information-only basis, a written or oral explanation of the current local COVID-19 response measures, personnel and equipment resources, numbers of critical patients and confirmed cases of COVID-19, and an explanation of why the local government would lack the capacity to respond to the consequences of a de-energization.
4. The utilities must not de-energize transmission lines or distribution circuits in counties with active shelter-in-place orders without first consulting with ~~receiving written confirmation from~~ the county emergency manager ~~that~~ regarding whether the de-energization will ~~not~~ exceed the local capacity to respond to the consequences of a shutoff. If the de-energization footprint includes a city with more than 100,000 inhabitants, the utility must also ~~receive written confirmation~~ consult with ~~from~~ the city emergency manager regarding whether the ~~that~~ de-energization will

~~not~~ exceed the local capacity to respond to the consequences of a shutoff, unless the city does not have a dedicated emergency manager.

5. The utilities must limit in scope and duration any de-energization action that would result in the loss of power to residential customers (or a vulnerable subgroup thereof) that are subject to a quarantine, shelter-in-place, or similar order or requirement when the heat index is at the "Danger" or "Extreme Danger" level, as determined by the National Weather Service.
6. If de-energization cannot be avoided, the utility must not shut off the power until absolutely necessary, must limit the de-energized areas through the use of temporary backup generation and grid-based solutions, and must prioritize the location(s) of Critical Treatment Facilities, as defined below, for re-energization.
7. By June 1, 2020, the utilities must partner with local governments and state agencies to identify all facilities currently being used to treat serious and critical condition patients, and all facilities that have been identified as planned or potential "overflow" treatment facilities for serious and critical condition patients <u>where the local government in whose jurisdiction the facilities are located anticipates that the facilities will house COVID-19 patients in the near future</u>. Facilities subject to this requirement shall be known as "Critical Treatment Facilities" ("CTFs"). CTFs may be temporary or permanent facilities and may include, but are not limited to, hospitals, urgent care centers, overflow critical care centers, <u>respite</u>

centers, rural clinics, nursing homes, skilled nursing facilities, hospice centers, hotels, and other essential public health facilities, such as laboratories that are testing for COVID-19 and morgues. The utilities must partner with local governments and state agencies to keep a list of all CTFs, and must ~~keep this list~~ update~~d~~ ¨this list within 24 hours of being provided ~~on a daily basis~~ new information by the local governments and state agencies for the duration of the COVID-19 response in California.

8. By June 1, 2020, the utilities must partner with local governments and state agencies to develop plans to ensure that all CTFs remain fully energized during any de-energization outage, and shall work with local governments to provide any necessary temporary backup generation to all CTFs. CTFs must have sufficient backup power and fuel reserves to remain energized for five days.[7] The utilities must ensure that CTFs receive priority notification of any potential de-energization. Any failure to provide notice will be explained in the utility's post-event report.

~~9. The utilities are prohibited from undertaking any de-energization activity that could result in a disruption to the power supply of any CTF. Prior to initiating any de-energization event, the utility must ensure that every CTF that could be impacted by the de-energization event has adequate backup power in place, has been provided notice of the impending de-energization event, and that the de-energization event will not result in any loss of power to the CTF.~~

[7] This timeframe is based on the back-to-back de-energization events in PG&E's service territory in late October 2019, which resulted in some customers losing power for close to a week.

10. By June 1, 2020, the utilities must partner with local governments, state agencies, and the identified large commercial customers to develop plans to ensure that essential business facilities, including but not limited to the following, remain energized during de-energization events: retail grocery stores; drugstores; pharmacies; shopping services that deliver groceries and essential household goods (e.g., Amazon, UPS, FedEx); funeral services; the facilities and transportation/delivery infrastructure that supply essential business facilities; gas stations; residential facilities for seniors and people with developmental disabilities or other conditions; and any other facilities identified in existing or future shelter-in-place orders. The utilities' plans must prioritize grid-based solutions for the transmission lines and distribution circuits serving the identified facilities, including sectionalization, system hardening, temporary portable generation at substations, and re-directing the flow of power, regardless of whether the facility is already equipped with backup generation. Where the facility is not already equipped with backup generation, or is equipped with limited backup generation, the utilities must work with local governments to ensure the facility is equipped with ~~provide~~ any necessary temporary backup power sufficient to allow each facility to withstand a five-day outage.
11. The utilities must keep a record of local facilities (e.g., schools, hotels, shelters, nursing facilities), identified and provided to the utilities by local governments, that house vulnerable populations and/or might be used as

evacuation shelters or Community Resource Centers that allow people to stay in separate rooms or provide sufficient social distancing. The utilities must partner with local governments to develop plans to ensure that these facilities remain energized during a de-energization event. The utilities' plans must prioritize grid-based solutions, regardless of whether the facility has backup generation, and include plans developed in partnership with local governments for temporary backup generation sufficient to withstand a five-day outage.

12. Telecommunications infrastructure must remain energized if any local or statewide shelter-in-place order is in effect. The utilities must partner with all companies owning, operating, or otherwise responsible for infrastructure that provide or otherwise carry 9-1-1, voice, text messages, or data ~~the telecommunications service providers~~ to ensure that reliable access to 9-1-1 and the distribution of essential emergency information ~~wireless, landline, emergency warning, 9-1-1, and all other services~~ can continue to be provided ~~remain operational~~ during a de-energization event, in accordance with the final resiliency protocols adopted in R.18-03-011. ~~The utilities and telecommunications service providers must ensure that telecommunications infrastructure is equipped with at least five days of backup power and provide such backup power if necessary.~~ The utilities must partner with local governments to develop a plan for emergency notifications and other critical communications in the event telecommunications services go down. Utilities must ~~immediately~~ notify

local governments and public safety partners of the telecommunications infrastructure located in the de-energization area, to the extent the utilities have that information, in advance of each de-energization event.

13. The utilities must develop a claims process for financial losses resulting from a de-energization event that occurs during a federal-, state-, or local-declared state of emergency or state or local shelter-in-place order related to COVID-19.

14. After any de-energization event occurring during a declared state of emergency or active shelter-in-place order related to COVID-19, that lasts for more than five hours, or any two de-energization events lasting two hours or more that occur in the same 48-hour period, the utility will provide all affected residential customers a bill credit, to be applied to the next billing cycle immediately following the de-energization event(s), in an amount set by the Commission to reasonably compensate those customers for grocery loss, including the cost of delivery service or similar benefit for impacted individuals located in areas where grocery delivery service is unavailable.

15. All de-energization events that impact a city, county, tribe, or community with a shelter-in-place order in effect due to COVID-19 shall be subject to an after-the-fact reasonableness review by the Commission specifically evaluating compliance with these emergency regulations, as well as the standard reasonableness review otherwise required. The reasonableness review will examine harm to public safety specific to COVID-19 from the

de-energization event, will be conducted within six months of the de-energization event, and will be made available to the public. Any utility that engages in a de-energization event that is unreasonable, overbroad, or is not conducted according to these rules shall be subject to sanction by the Commission.

The moving parties also request that, if the Commission adopts the proposed emergency regulations in part or in full, the utilities be required to report their compliance to the Commission via existing de-energization reports or a new reporting requirement. At a minimum, the Moving Parties recommend that the utilities provide monthly updates listing the local governments with which they have met, the issues addressed in those meetings, issues identified for future meetings, planned future meetings, and progress implementing the regulations.

Alternatively, if the Commission determines that any of the activities encompassed by the proposed regulations are already mandated by the existing de-energization regulations, the Moving Parties request that the Commission modify the requirements to expressly incorporate the proposed regulations into the existing ones.

If the Commission determines that additional stakeholder input is necessary before adopting emergency de-energization regulations for the COVID-19 pandemic, the Moving Parties support the recommendation of the Public Advocates Office that the Commission direct that all stakeholders be allowed to submit written comments addressing the proposed regulations on an expedited timeline.[8]

[8] Public Advocates Office Response, pp. 1, 4, 5–7.

III. THE PROPOSED REGULATIONS ARE NECESSARY AND FEASIBLE

PG&E notes that the Moving Parties are not writing on a blank slate: this is correct[9] The Moving Parties conceived of and drafted the proposed emergency regulations largely because of PG&E's disastrous de-energization activities in 2019. The proposed regulations place heavy emphasis on requiring consideration of the public safety risks of turning off the power, as well as the risks of wildfire that would be mitigated by de-energization, because of the serious harms suffered by PG&E customers during multiple extended outages in 2019 that were not avoided, nor were they adequately prepared for or mitigated. The proposed regulations place heavy emphasis on planning and coordination because PG&E largely refused to meaningfully coordinate and plan with local governments before the 2019 fire season and largely failed to coordinate effectively with local governments during fire season.[10] The proposed regulations place heavy emphasis on effective information sharing because PG&E largely failed to provide useful and timely information to public safety partners and the public regarding de-energization events in 2019,[11] and because some of PG&E's local governments are still experiencing issues obtaining information from the utility now. The proposed regulations emphasize the need for the utilities to understand and take into account the situation on the ground in the communities that will be de-energized because PG&E's de-energization events have yet to reflect such an understanding or analysis in their scope or execution. And the

[9] PG&E Response, p. 11.

[10] The Joint Local Governments have acknowledged in previous filings that certain of PG&E's de-energization team did make an effort to meet with the Joint Local Governments' members and understand their needs, and that some improvements to the de-energization program resulted from those discussions. The Joint Local Governments stand by those acknowledgments. The fact remains, however, that PG&E's focused efforts were not enough to produce a rational or reasonable de-energization program or well-executed events.

[11] See, e.g., R.18-12-005, *Order to Show Cause Why PG&E Should Not Be Sanctioned by the Commission for Violation of Public Utilities Code Sections 451, Commission Decision 19-05-042, and Resolution ESRB-8* (November 12, 2019).

proposed regulations call for specific mitigation measures for impacted customers because PG&E has failed to provide effective mitigation itself. SCE and SDG&E fared better in 2019, though their de-energization events also showed areas where improved analysis, planning, communication, coordination, and customer protections are necessary. The Moving Parties, whose members, customers, and constituents all experienced and had to manage the on-the-ground impacts of the utilities' de-energization events, are asking for the proposed regulations because we have already seen the writing on the proverbial slate and it tells a story that we do not want to read again in 2020. This time, it will be much worse for California's communities battling the COVID-19 pandemic.

The utilities, to varying degrees, claim they have changed their de-energization protocols since 2019 to such an extent that the proposed regulations are unnecessary, even in previously uncontemplated pandemic conditions. As the Moving Parties' members have repeatedly reminded the utilities and the Commission, the true test of an effective de-energization program is how well its measures are working in practice. Making a plan look reasonable and workable on paper is relatively easy; making it effective in practice is much harder and is an outcome that the utilities have not yet fully achieved, even under conditions where the concerns about high fire risk were not playing out during an unrelated, all-consuming disaster. SDG&E has the best track record in practice, though by no means a perfect one, and the counties it serves have reported productive working relationships with their utility. The Moving Parties' member counties saw areas for improvement in SCE's 2019 de-energization events, though they did not cause the level of chaos that PG&E's did. Following the 2019 de-energization events, the Moving Parties' members have seen increased coordination from SCE and some have expressed optimism about their working relationship with the utility going forward. In the wake of the 2019 events, PG&E's local governments have seen increased outreach and coordination from the utility, on average, but the Moving Parties caution that PG&E's claim to be working "closely" with governmental partners to identify facilities being used to respond to the pandemic and ensure backup generation must be taken with a grain of salt.[12] PG&E has been working with some of the local governments in its service territory more closely than with others, but "closely" as an accurate descriptor of PG&E's working relationship with all of its local governments is a milestone that has yet to be achieved.

Despite the utilities' improvements, the Moving Parties do not currently see the level of preparedness and coordination they believe is necessary to conduct de-energization events during the COVID-19 pandemic in a manner that does not make a bad situation worse. Neither do the Moving Parties see that the utilities are adequately considering the impacts of power outages themselves, which are emergencies that create harm for the impacted communities and particularly for the most vulnerable individuals in those communities. That is why the Moving Parties have asked the Commission to adopt the proposed regulations.

The Moving Parties are not asking the Commission to give us something we already have.

A. <u>The Proposed Regulations Do Not Diminish Public Safety</u>

The proposed requirements for robust analysis, coordination, planning, communication, and information-sharing before and during de-energization events will not diminish public safety.[13] De-energization events are emergencies, just like floods, earthquakes,

---

[12] PG&E Response, p. 17; see also *id.* at Appendix A, *passim*. For example, this week Marin County's Office of Emergency Services received for the first time PG&E's list of critical facilities in the County. The County's Assistant Emergency Services Manager has been asking for that list for approximately 18 months. The City of San Jose and County of Santa Clara have also had limited communication with PG&E following the 2019 de-energization events.

[13] See PG&E Response, p. 14; SCE Response, p. 4; SDG&E Response, pp. 7–9; CUE Response, *passim*.

wildfires, and the COVID-19 pandemic. Emergencies have immediate and direct impacts on individuals and communities; emergencies are also managed at the local level. The bedrock elements of effective emergency management are planning, coordination, and accurate and timely information. The proposed regulations do not wrest de-energization decisionmaking from utility control, as is discussed in detail below, but they do require a significant level of close coordination. Ensuring that the utilities have engaged in robust analysis, coordination, and planning with local governments and state agencies to ensure that de-energization events are limited in frequency and scope to those occasions and locations that are absolutely necessary, and that, within those locations, Critical Treatment Facilities and other critical facilities necessary for public safety have been identified, that their backup power capabilities have been evaluated, and that plans are in place to ensure that a de-energization event has the least impact possible on those facilities will improve public safety, not diminish it.[14]

Requiring the utilities to have a thorough understanding of the situation on the ground in the communities potentially impacted by de-energization will also improve public safety, as will requiring the utilities to analyze the benefits of de-energization compared to the potential public safety risks.[15] If a local government's resources have been so depleted by COVID-19 that it cannot respond to the impacts of a de-energization event, that is critical public-safety information that the utility needs to know to conscientiously weigh the benefit of de-energization against the potential public safety risks.[16] And if a de-energization event will endanger the lives of COVID-19 patients, that is also information the utility needs to have before de-energizing.[17] The Moving Parties are asking that the Commission adopt regulations to require

[14] Proposed Regulations 1, 3, 4, 5, 6, 7, 8, 10, 11, 12.
[15] Proposed Regulations, 1, 2, 3, 4
[16] D, 19-05-042, pp. A22–A23, A25–26; Proposed Regulations 3 and 4.
[17] Proposed Regulations 1 and 2.

this level of planning, coordination, analysis, and information-sharing because the utilities—for all their protestations about the existing rules and their de-energization improvements—have not reached these benchmarks on their own.

The utilities' arguments about the increased risk to public safety from the proposed regulations are revealing: they focus on increased risk of wildfire to the exclusion of all other harms from de-energization.[18] The impacts of catastrophic wildfires are serious and the Moving Parties do not take them lightly or underestimate their significance. The local government members of the Moving Parties were on the front lines of the wildfires that precipitated the utilities' de-energization authority, both in terms of being impacted by the fires and having to manage the local emergency response.[19] With that in mind, the utilities' obligations regarding de-energization are broader than simply shutting off the power to prevent catastrophic wildfires. The utilities are obligated to prove that de-energization is necessary to protect public safety; to effectively do so, they must rely on other available measures as an alternative to de-energization, they must make efforts to mitigate adverse impacts of de-energization on customers and communities, and they must de-energize only as a last resort.[20] In the wake of the significant economic and social impacts of the 2019 de-energization events, the Commission opened two proceedings to examine whether and to what extent the large utilities failed to implement the existing de-energization rules.[21] The utilities are also required to demonstrate to the Commission the decision criteria leading to de-energization, including an evaluation of the alternatives that were considered and the mitigation measures implemented to decrease wildfire risk, and an explanation of how the utility determined that the benefit of de-

---

[18] See PG&E Response, p. 14; SCE Response, p. 4; SDG&E Response, pp. 7–9; CUE Response, pp. 3–5.
[19] CUE's Response appears to dismiss this fact. (CUE Response, pp. 2, 5, 6.)
[20] See Resolution ESRB-8, pp. 1, 4. ; D.19-05-042, p. A1.
[21] R.18-12-005, Order to Show Cause; I.19-11-013.

energization outweighed the potential public safety risks.[22] A well-reasoned decision to de-energize must take into account the entire spectrum of potential harms, including harms specific to COVID-19. This has been a failing of the utilities with regard to their 2019 de-energization activity, during which they only reported on how their decision to turn off the power would reduce risk of wildfire ignition from utility facilities. It is also a failing in their responses to the joint motion, which continue to insist that their only obligation is to reduce wildfire risk.

In this time of pandemic, the utilities' obligation to consider the harms of an extended power outage has become even more important than it was previously. For this reason, one of the key requests of the Moving Parties is for the Commission to provide more emphasis on the obligation the utilities already have to balance safety risks.

B. <u>The Proposed Regulations are Consistent with Existing De-Energization Regulations and Principles</u>

The overarching guidelines for the existing de-energization regulations focus on reducing the risk of utility-caused wildfires while balancing the overall risks to public safety; use of de-energization as a last resort; effective education, notification, and communication to customers; coordination with multiple state and local jurisdictions and agencies; seamless integration with public safety partners for communication and notification; development of protocols consistent with those established for other types of emergencies; reporting on lessons learned; and adoption of best practices.[23] The regulations proposed in the joint motion are consistent with these guidelines and the principles they espouse.

PG&E's argument to the contrary adopts much of the Commission's own prior discussion of de-energization without acknowledging the utility's past arguments resisting

---

[22] D.19-05-042, pp. A23–A24 (Reporting requirements 1 and 7). Aside from providing detailed descriptions of prevailing weather conditions in their after-action reports, the large utilities have yet to provide post-event justification explanations that contain the required information.

[23] D.19-05-042, pp. A1–A3 (Overarching Guidelines).

adoption of certain of the existing regulations and without acknowledging its own failures to effectively implement them.[24] PG&E does correctly identify several key principles of the existing de-energization framework: safety of individuals and communities; de-energization as a last resort necessary to prevent catastrophic wildfires; de-energization events must be as narrow in scope and duration as safely possible; the utilities must take appropriate steps to mitigate the impacts of de-energization on the public; and extensive coordination among many parties.[25] PG&E's premise that these five principles are incompatible with the proposed regulations, however, is incorrect. The proposed requirements, as discussed above and in greater detail below, are based on and are consistent with the existing de-energization framework.

1. Coordination with state and local emergency management entities before de-energization

Proposed regulation No. 1 requires that, prior to implementing a de-energization event, a utility must coordinate with local emergency managers within the potential outage footprint, CalOES, Cal FIRE, and the Safety and Enforcement Division to evaluate the need for de-energization and to assess the potential impacts. This is an enhancement to the existing requirements that the utilities must provide priority notification to state and local public safety partners,[26] provide public safety partners the most accurate and specific situational awareness information available at the time of first notification,[27] and provide operational coordination to public safety partners to ensure they have the information (including critical facilities, circuits, and impacted medical baseline customers) needed to coordinate with the utility and effectively prepare for de-energization.[28] It also enhances the existing requirement for the utilities to

[24] PG&E Response, pp. 11–13.
[25] *Ibid.*
[26] D.19-05-042, pp. A7–A8, A16.
[27] *Id.* at pp. A16–A17
[28] *Id.* at p. A15.

analyze the risks, mitigations, and potential harms associated with each de-energization event.[29] The purpose of the regulation is to ensure that the utility is prepared to fully consider the risks of turning off the power, as well as the risks of keeping the power on, and it also ensures that the utilities are fully informed of local conditions relevant to public safety,[30] and that the decision to de-energize is carefully considered in light of all available information. The proposed regulation is consistent with existing de-energization rules and principles.

The consultation process does not need to be cumbersome, as the utilities fear.[31] Under the existing public safety partner notification process, the utilities notify CalOES using a written form when the utility believes a de-energization event may be necessary; at some point after notifying CalOES, the utility notifies potentially impacted local governments via email, phone call, and/or automated message. For example, under the proposed guideline, on receiving notification of the potential de-energization, the state and local emergency managers would provide the utility with a briefing or summary containing relevant COVID-19 conditions—state allocation of emergency resources, backup generator failure at a hospital or Critical Treatment Facility, number of patients in overflow medical facilities, etc. The utilities and local emergency managers communicate via email and telephone before and during de-energization events; adding a specific communication relating to local COVID-19 conditions will not present an insurmountable hurdle. Any necessary follow-up on the local or state COVID-19 conditions as they relate to the impending de-energization event can be done at the request of the utility, the state, or the local emergency managers, and can be done directly between the utility and requesting party, if the issue does not have broad applicability, or can be incorporated into one of

[29] *Id.* at pp. A23–A24.
[30] The Moving Parties agree with CASMU's observation that coordination and information-sharing is a two-way effort. (CASMU Response, p. 6).
[31] See PG&E Response, pp. 14–17; SDG&E Response, pp. 7–12; SCE Response, pp. 7–8.

the utility's regular operational briefings. Ultimately, as the proposed regulation states, the decision to de-energize remains with the utility. But effective coordination and communication with local governments is key to minimize harm to the public.

The Moving Parties propose certain clarifications to the language of this regulation, as shown in Section II, to remove ambiguity about the nature of the coordination the utilities must undertake with local and state government entities.

2. Quantitative and Qualitative Analysis

Proposed regulation No. 2 requires the utilities to perform an analysis of the risk of utility-caused ignition and resulting catastrophic wildfire from the impending weather event and compare the result of the analysis with the harms that are likely to result from de-energization; it also proposes a number of criteria to be included in that analysis. This proposed regulation is simply an enhancement of the existing requirement that the utilities provide the Commission with a full explanation of the decision criteria leading to de-energization, including an evaluation of the alternatives considered and mitigation measures used to decrease the risk of utility-caused wildfire in the de-energized area, and an explanation of how the utility determined that the benefit of de-energization outweighed potential public safety risks.[32] The current regulations require the utilities to provide this written analysis to the Commission 10 days after each de-energization event, but the utilities must perform these analyses before shutting off the power—otherwise their after-action reports would be works of fiction. This proposed regulation appears to cause the utilities a significant amount of anxiety, but given that the recommended factors do not significantly change the analysis that the utilities are already required to consider, the Moving Parties are at a loss to understand why.

[32] D.19-05-042, pp. A22–A23.

Factors (a) and (b), the number of hospitalized COVID-19 patients and reported COVID-19 cases in the de-energization footprint, involve information that can be obtained through publicly available sources or provided by state agencies or local governments. To address concerns regarding the ready availability of the information, the Moving Parties have proposed changes to the language, as shown in Section II. The Moving Parties recommend that the utilities obtain the California Department of Public Health's published licensed bed counts for hospital beds and skilled nursing facilities. State agencies and local governments can provide the utilities with information about hospital surge capacity or other relevant patient-related information as necessary before or during de-energization events. The utilities already know (or *should* know) the locations of the hospitals and other established medical facilities in every county; overlaying a parcel-level outage footprint over the critical medical facility map will quickly identify the impacted hospitals.

Factor (c), the number of AFN individuals in the outage footprint, including customers enrolled in the utilities' medical baseline program, customers identified as ineligible for transition to default TOU based on identification of a household member as having a chronic illness or other medical condition, customers who receive bills or other notices in alternative formats or languages other than English, customers who have otherwise self-certified as having a disability, and customers enrolled in CARE, FERA, and any other income-assistance programs relies on information the utility has internally. While there are likely to be additional AFN households that are not included in the existing utility data, the Moving Parties are not asking the utilities to go outside of their own resources with regard to this proposed regulation. Even though the utility databases are likely to be incomplete, this requirement will allow the utility to identify a substantial number of AFN households that will potentially be impacted by a de-energization event, which is a critical component of any analysis of potential harm to public safety from de-energization; that understanding, in turn, is a factor in the already-required harm–benefit analysis for the decision to de-energize.

Factor (d), the number and type of critical facilities in the de-energization footprint, and the known or likely results of de-energizing those facilities, is information that the utilities have already been charged with identifying, and it should therefore be readily available to them. The utilities are already required to identify critical facilities, in partnership with local governments,[33] and identifying the potentially impacted critical facilities should be straightforward. The utilities are also already required to help critical facilities assess their need for backup generation and determine whether additional equipment is needed, including providing temporary backup generators to facilities or infrastructure that are not well prepared for a power shutoff.[34] The utilities should therefore have both general knowledge (wastewater facility loses pumping ability, potential health risks arise) and specific knowledge (specific facility is in the process up upgrading its electrical system for a backup generator) about the impacts of de-energization on the affected critical facilities. To the extent the utilities are inclined to argue that this is too much information about too many facilities to have to analyze, the Moving Parties disagree. The considerable power that comes with having authority to shut off the electricity to large parts of the grid comes with equally considerable responsibilities, including the obligation to understand the potential impacts of de-energizing. Moreover, these regulations were already in place for the 2019 wildfire season.

Factors (e) and (f), the wind speed-related failure thresholds of the transmission lines and distribution circuits likely to be impacted by the high-wind event, and up-to-date

[33] D.19-05-042, p. A11.
[34] D.19-05-042, p. A12.

weather modeling showing areas of highest actual or predicted wind speeds, are information the utilities have readily available. This information also appears to be the data that the utilities primarily rely on in making de-energization decisions, which means the utilities will have analyzed it in any event. The Moving Parties propose to clarify the language in factor (e), as shown in Section II.

Factor (g), the status of vegetation management work completed along the transmission lines and distribution circuits under consideration for de-energization, is also information the utilities should have readily available, particularly because vegetation management is a key part of the utilities' effort to reduce the risk of wildfire without the need to resort to de-energization. Part of the utilities' de-energization analysis is whether there are un-abated risk trees or other vegetation that could blow into the power lines and spark a wildfire.[35] The status of vegetation management work is relevant to that risk analysis.

Factors (h) and (i), an explanation of the options for keeping potentially impacted infrastructure energized, including sectionalization, temporary portable generation, redirecting power, and real-time observation, and the available personnel and resources that can be put into the field to monitor real-time conditions on potentially impacted transmission and distribution infrastructure, provide a framework for the utilities to share more detail regarding the analysis the utilities are already required to provide.[36]

Factor (j), the estimated individual and community financial losses, including spoiled food and medication, lost revenue by small businesses, lost wages, and other similar harms based on damage claims submitted to the utilities following the 2019 de-energization events, is a factor in the analysis of harms created by de-energization events. The proposed

---

[35] See, e.g., PG&E After-Action Report for October 23, 2019 PSPS Event, p. 6.
[36] D.19-05-042, pp. A22–A23 (Reporting requirements 1 and 6).

analysis is based on claims information submitted to the utilities, which means there are no barriers to obtaining it. While actual losses suffered during the 2019 de-energization events have been estimated as much greater than the level of claims submitted, the proposed regulation is limited to the claims specifically to allow for analysis by the utilities without the need to seek information from external, potentially conflicting sources.

Factor (k), the estimated increased medical risk to affected populations, including the AFN population, including risk of harm due to nonfunctioning medical devices, increased risk of poor health outcomes due to lost medication, risk of harm due to lost ability to manage indoor temperature, increased response time for emergency calls due to demands on the emergency response system, and other similar medical risks, is a significant part of the public safety risks created by de-energization that the utilities are already required to analyze.[37] A substantial amount of information has been made available in this docket and to the utilities via the claims process about the harms experienced by AFN individuals as a result of the 2019 de-energization events. Prior to the events of 2019, inadequate consideration was given to the medical impacts of an extended power outage, not only on customers enrolled in the medical baseline program, but also on others who rely on power to sustain their ability to conduct everyday tasks to live independently. The 2019 events gave greater insight into the level of medical need, ranging from seniors trapped in their building due to non-functioning elevators, to insulin-dependent diabetics who lost access to life-sustaining (and expensive) medication, to people who rely on respirators to breathe. These people, who are at the greatest risk of harm

[37] D.19-05-042, p. A24.

from de-energization, and also at the greatest risk if they are exposed to COVID-19, must be given additional consideration before de-energization is conducted in the midst of a pandemic.[38]

In light of the existing requirements to analyze and quantify the potential harms and risks of de-energization events before shutting the power off, which the proposed factors flesh out or expand upon, the utilities' arguments that it would be unreasonable or unworkable to produce such an analysis before a de-energization event are difficult to understand.[39] The Commission already requires the utilities to explain how they determined that the benefit of de-energization outweighed potential public safety risks.[40] That explanation necessarily requires a balancing of harms and benefits, risks and rewards—which is what the proposed regulations also ask for, but with more detail regarding the factors to be considered.

Notwithstanding the existing requirements, it is true that none of the utilities have provided the required analysis in their after-action reports. This is an ongoing concern among the Moving Parties, and the issue has been addressed extensively within the record of this proceeding. The utilities have regularly failed to provide this information, submitting only a brief gloss over their decisionmaking process in their required after-action reports. For example:

- Most of PG&E's after-action reports contain conclusory statements to the effect that "[t]he [Officer In Charge] determined alternatives to de-energization were not adequate to reduce this risk and that the public safety risk of catastrophic wildfire outweighed the public safety impacts of

---

[38] PG&E references its efforts to work with CFILC to provide support for customers with medical needs during de-energization events. (PG&E Response, p. 8.) While this program is welcome, its scale is small, and it is not positioned to provide support for all customers with medical vulnerabilities, even without the added complexities of COVID-19.
[39] SDG&E Response, pp. 9–11; PG&E Response, pp. 15–17; SCE Response, pp. 7–8;CUE Response, p. 4.
[40] D.19-05-042, p. A24.

the proposed de-energization scope."[41] The alluded-to public safety impacts are never enumerated or evaluated.

- All of SCE's after-action reports for the October 2019 de-energization events contain the statement that "SCE coordinated closely with local fire authorities and emergency management personnel to identify any potential public safety risks associated with de-energization, and none were noted."[42] SCE provides more information than PG&E about its evaluation process and the conclusion that no public safety risks associated with de-energization were identified sheds some light on what SCE considers a public safety risk, but SCE's explanation is still conclusory and does not allow the Commission to evaluate whether SCE's de-energization decisions were reasonable.
- SDG&E's after-action reports for its two de-energization events in 2019 state that, based on weather forecasts and other environmental factors, "SDG&E determined that initiating PSPS in these areas was the best method to mitigate the risk of a fast-spreading wildfire."[43] This addresses wildfire risk, but makes no mention of public safety risks related to de-energization.

---

[41] See PG&E After-Action Report for June 9, 2019 PSPS Event, p. 3; PG&E After-Action Report for October 5, 2019 PSPS Event, p. 3; PG&E After-Action Report for October 23, 2019 PSPS Event, p. 7; PG&E After-Action Report for October 26 and 29, 2019 PSPS Events, p. 8; PG&E After-Action Report for November 20, 2019 PSPS Event, p. 5.
[42] SCE After-Action Report for October 1–12, 2019 PSPS Event, p. 18; SCE After-action Report for October 12–21, 2019 PSPS Event, p. 14; SCE After-Action Report for October 21–26, 2019 PSPS Event; SCE After-Action Report for October 27–November 4, 2019 PSPS Event, p. 18.
[43] SDG&E After-Action Report for October 10–11, 2019 PSPS Event, p. 3; SDG&E After-Action Report for October 20–November 1, 2019 PSPS Event, p. 6.

Based on the 2019 de-energization reports, it is not clear whether the utilities have ever performed the required analysis.[44] The proposed emergency regulations would clarify that this existing obligation cannot be avoided and would provide greater specificity of the factors to be considered.

SDG&E's argument that it does not have the time before a de-energization event to perform the analysis proposed by the Moving Parties raises several questions.[45] Given that the utilities are already required to determine that the risks of a catastrophic wildfire outweigh the potential public safety risks of an extended power outage before de-energizing, and given SDG&E's assertion that the utilities do not have the time to analyze the big-ticket electrical system factors and on-the-ground risks before shutting the power off, what *are* they currently basing their de-energization decisions on? SCE states that it considers the proposed factors that are related to actual threat of wildfires—wind speed thresholds, weather modeling, vegetation management, and sectionalizing circuits—in its de-energization decisions.[46] Those factors only address one side of the required de-energization analysis: the risk of a catastrophic wildfire. The other side of the safety analysis, which the utilities are already obligated to undertake, is to determine the potential public safety risks of de-energizing.

The record of Phase 1 of this proceeding, where the Commission adopted the existing requirement for the utilities to balance the risk of harms, includes extensive information about the hazards of de-energization, particularly on AFN households. Since the regulations were issued, the experiences of the 2019 wildfire season and the resulting Commission actions to investigate the utilities' performance[47] has enhanced the record with substantial additional

---

[44] See also AT&T Response, p. 5; CCTA Response, p. 2; MGRA Response, p. 2; TURN Response, p. 2.
[45] SDG&E Response, p. 11.
[46] SCE Response, p. 8.
[47] R.18-12-005, Order to Show Cause; I.19-11-013.

information about the harms of extended power outages. Given the failures of the 2019 events and the COVID-19 pandemic, which raises the stakes of de-energization yet further, the clarifications of this requirement are appropriate and necessary. This is even more clear in light of the utilities' past opposition to reporting requirements, including the argument that the existing reporting requirements in Resolution ESRB-8 were sufficient and PG&E's recommendation that the Commission delay consideration of the issue of weighing public benefits against public safety risks until Phase 2.[48] Notwithstanding these arguments, the Commission adopted the more detailed reporting requirements, including the public safety benefit–harm analysis, which the utilities have failed to provide to date.

The Moving Parties also note that the proposed analysis would be *provided to* state agencies and local emergency managers. The Moving Parties do not propose that the recipients would then have the opportunity to haggle with the utilities over the calculations or question the inputs. But, as the Moving Parties, have emphasized, robust information-sharing is a critical aspect of effective emergency management. Information relating to the utilities' assessment of the potential public safety benefits and public safety harms of an impending de-energization event is particularly relevant. Moreover, the Moving Parties are confident that, if ordered to produce this analysis, the utilities will identify the least burdensome format in which to provide the information, such as a multi-tab Excel spreadsheet.

Finally, regardless of whether the Commission adopts this proposed regulation in whole or in part as a requirement for information-sharing in advance of shutting off the power, the Commission should require the utilities to provide a detailed analysis in their after-action reports, including the articulated factors, explaining how they determined the potential benefits of de-energization outweighed the potential public safety risks of an extended power outage.

[48] D.19-05-042, pp. 65–66, 108.

That analysis should use the factors recommended by the Moving Parties, or other similar factors that the Commission deems appropriate or necessary.[49]

3. Local Government Requests for De-Energization Exemption

Proposed requirement No. 3, which would allow local governments to request, and receive, exemptions from de-energization on a per-event basis if the local government's public safety capabilities have been degraded by COVID-19 such that a de-energization event would exceed the local capacity to respond to the consequences of a shutoff, is simply an extension of the existing rules that allow public safety partner requests to delay de-energization and to re-energize certain areas.[50] In the Phase 1 decision, the Commission determined that the utilities should address requests for a de-energization delay from public safety partners on a case-by-case basis; the Commission further determined that the utilities retain the ultimate decision to grant a delay and responsibility to determine how a delay in de-energization would impact public safety.[51] Under the proposed regulation, local government requests for de-energization exemption based on exhaustion of local response capability would be evaluated and decided under the same terms. It is necessary, however, that exemptions be a real possibility, given the serious public safety implications of de-energizing a community that is not equipped to respond effectively.

In Phase 1, the Commission also directed the utilities to work with public safety partners before wildfire season to develop preliminary plans for addressing emergency situations that may arise during the de-energization, such as a non-utility caused wildfire that occurs in a de-energized area that necessitates the use of water for firefighting purposes.[52] The Commission

---

[49] See Public Advocates Office Response, p. 5.
[50] D.19-05-042, pp. A25–A26.
[51] *Id.* at p. A25.
[52] *Id.* at p. A26.

determined that a situation like that could result in the public safety being better served by utility lines being re-energized.[53] This directive, which has been in place for nearly a year, addresses the same fundamental public safety concern that the Moving Parties seek to address through local government exemption requests: there may be situations where the public is safer with the power on. That is also why the proposed regulations call for robust coordination, planning, and information-sharing between the utilities and government entities responsible for responding to emergencies. The public is always safer when the entities in charge of ensuring societal continuity plan ahead, plan for a broad range of eventualities, and work together. For all the improvements it has made recently, PG&E has yet to demonstrate that it is capable of this level of engagement with local governments; SCE and SDG&E have done a better job, but their local government coordination will still benefit from added rigor.

Because the proposed regulation allowing local governments to request and receive exemptions from de-energization does not depart from the existing framework that allows public safety partners to request de-energization delays but leaves the ultimate decision with the utility, and because it requires robust coordination between utilities and public safety partners to plan for situations where the public safety is better served by leaving the power on, the utilities' arguments about jurisdiction, liability, improper delegation of authority, and usurpation of the decisionmaking process are moot.[54]

4. Written Confirmation of Local Government Capacity to Respond to Consequences of De-Energization

Proposed regulation No. 4, which would require the utilities to consult with county emergency managers, or the city emergency manager for cities with more than 100,000

---

[53] *Ibid.*
[54] PG&E Response, pp. 14–17; SDG&E Response, pp. 7–12; SCE Response, pp. 7–8. See also CUE Response, p. 4–5; CASMU Response, p. 8.

inhabitants, before initiating a de-energization regarding whether the local government's response to COVID-19 has rendered the local government unable to respond to the consequences of a shutoff, is about communication. This requirement would ensure that the utilities are aware of serious potential public safety issues in specific communities. The Moving Parties propose to clarify the language of the original regulation and to address parties' concerns regarding written confirmation, as shown in Section II. The proposed regulation does not give local governments veto power over de-energization decisions and it does not present any insurmountable logistical barriers. Moreover, if a community's emergency resources are so depleted that a de-energization event would exceed local response capabilities, that is critical information that the utility needs to know.

The logistics of implementing this regulation should be straightforward. Local emergency managers and the utilities already communicate directly with each other before and during de-energization events via email and telephone. While it is possible that a situation may arise where the utility either has to shut off the power with only a few minutes' warning, or where the power unexpectedly shuts off due to irregular switching configurations or other technical errors, the Moving Parties are confident that under virtually all circumstances local emergency managers will have enough time to raise with the utility serious concerns about whether local emergency resources are maxed out by COVID-19. The utilities can build a request for information about local response capabilities into the existing notification and communication practices. For example, each email update regarding the potential de-energization can contain a request that the impacted local governments, through the Operational Area or by direct reply, provide any relevant information about local response capabilities to handle the de-energization.

5. Limiting Scope and Duration of De-Energization Events During High-Heat Days

Regulation No. 5, which requires the utilities to limit in scope and duration any de-energization event that would impact residential customers subject to a shelter-in-place or similar order, is a refinement of the existing requirement to de-energize only as a measure of last resort.[55] This regulation addresses the general risk of spreading infection if households are forced to leave their homes despite a stay-at-home order due to high temperatures; it also addresses increased risk of medically vulnerable individuals' exposure to COVID-19 if they are forced to expose themselves to other people in order to seek an air-conditioned environment.[56] While the utilities' after-action reports have demonstrated that they undertake some activities and analyses to limit the size and duration of de-energization events,[57] it is not clear, based on the 2019 events and the utilities' current efforts to refine their weather modeling, situational awareness, and other data that inform de-energization decisions to avoid a repeat of 2019, that these events are actually as small and short as they can be.[58] The Moving Parties therefore believe that it is appropriate to require a rigorous analysis for de-energization events during the COVID-19 pandemic, and particularly when temperatures are high enough to increase risk of harm to vulnerable individuals. This requirement does not, as PG&E argues, suggest a new legal standard for the scope and duration of de-energization events.[59]

---

[55] Resolution ESRB-8; D.19-05-042, p. A1.
[56] The proposal is not, as SDG&E posits, merely designed to preserve the comfort of residential customers who use air conditioning. (SDG&E Response, p. 13.)
[57] See also SCE Response, p. 8; SDG&E Response, p. 13; PG&E Response, p. 17.
[58] SDG&E appears closer to achieving this goal than PG&E or SCE.
[59] PG&E Response, Appendix A, p. A-3.

6. Ensuring Duration and Scope of De-Energization Events are as Small as Possible

Regulation No. 6, which requires the utilities to avoid shutting off the power until absolutely necessary, to limit the scope of the de-energization with temporary backup generation and grid-based solutions, and to prioritize re-energization of Critical Treatment Facilities, is a refinement of existing requirements that the utilities de-energize only as a last resort, use grid-based solutions to mitigate impacts, and provide backup generation to critical facilities where necessary.[60] Because of the potentially serious consequences of de-energization during the COVID-19 pandemic, and because, as discussed in the preceding section, it is not clear that the utilities' de-energization events have been as small and short as possible, the Moving Parties believe it is appropriate to refine the existing regulations by providing more specificity about the actions the utilities must take. The requirement to prioritize re-energization of Critical Treatment Facilities is consistent with the principle that de-energization events should do as little harm to the public as possible, and, in practice, is not a departure from the status quo. In one of the 2019 events, for example, PG&E was able to re-energize the Butte County jail, a critical facility that posed a public safety risk if left without power for an extended period of time, after the jail's generator unexpectedly failed. Moreover, the proposed refinements to the existing regulations would not, as PG&E speculates, require the utilities to continue delivering electricity past the point at which shut-off would be justified for public safety purposes.[61]

7. Identification of Critical Treatment Facilities

Proposed regulation No. 7, which requires close coordination between the utilities and local governments and state agencies to identify critical medical facilities necessary to treat COVID-19 patients, is an extension of the existing requirement that the utilities partner with

---

[60] D.19-05-042, pp. A1, A11–A12, A22–A23.
[61] PG&E Response, Appendix A, p. A-4.

local governments to identify critical facilities.[62] The proposed regulation enhances the existing requirement to focus on the medical facilities with patients in serious condition, including any temporary facilities that may be put in place to respond to the pandemic. The utilities need this information to fully assess the potential public safety impacts of de-energization. Local governments (primarily at the county level) and state agencies are the best source of information for identifying facilities, and can provide it to the utilities, as SDG&E suggested.[63] In fact, certain of the Moving Parties' local government members have already begun providing information about Critical Treatment Facilities to the utilities.

The Moving Parties do, however, propose to revise the regulation to require the information to be updated by local governments and state agencies on an as-needed basis, rather than daily.

8. Partnering with Local Governments to Ensure Critical Treatment Facilities Remain Energized

Proposed regulation No. 8 requires planning and coordination between utilities and local governments and state agencies to ensure that Critical Treatment Facilities remain fully energized during de-energization events; this process includes working together to provide any necessary temporary backup generation to these facilities. This is a refinement of the existing requirement that utilities work with critical facilities to assess their backup generation needs and capabilities and to provide generators to facilities that are not well-prepared for a power shutoff.[64] The proposed regulation makes clear that this requirement includes medical facilities that are integral to the COVID-19 response.

[62] D.19-05-042, pp. A11–A12.
[63] SDG&E Response, p. 14.
[64] D.19-05-042, p. A12.

This regulation, on its face, does not mandate that utilities provide backup generation to every Critical Treatment Facility in their service territory.[65] SCE is correct that hospitals and certain other Critical Treatment Facilities are legally required to have backup generation.[66] The key aspect of the proposed regulation is that the utilities and government entities *work together* to identify these facilities, confirm their backup power capabilities, and *coordinate* their efforts to ensure that facilities that need help receive it. During the COVID-19 pandemic, this information and preparation constitutes basic situational awareness.

After considering the parties' responses and reviewing the structure of the proposed regulations, the Moving Parties determined that regulations No. 8 and 9 could be combined. As shown in Section II, the priority notification requirement originally contained in regulation No. 9 has been incorporated into regulation No. 8, and the remainder of regulation No. 9 has been deleted. The proposed requirement for priority notification to Critical Treatment Facilities is an extension of the existing requirement to provide priority notification to critical facilities, which already include a number of healthcare facilities.[67] These facilities are where people who are at direct risk of immediate, physical harm during an extended power outage are located. Ensuring priority notification is critical.

9. Ensuring Continuous Power Supply to Critical Treatment Facilities

As discussed above, the Moving Parties propose to consolidate regulations No. 8 and 9. For ease of reference, however, the remaining proposed regulations are discussed using the numbering in the joint motion and in the parties' responses.

---

[65] SDG&E Response, pp. 14–15; SCE Response, pp. 8–9; PG&E Response, p, 18; TURN Response, pp. 4–7.
[66] SCE Response, pp. 8–9. See also TURN Response, p. 6.
[67] D.19-05-042, pp. A11–A12.

10. Identification of Essential Business Facilities

Proposed regulation No. 10, which requires the utilities to partner with local governments, state agencies, and large commercial customers to develop plans to ensure that essential business facilities remain energized during de-energization events, is an extension of the current requirements to partner with local governments to identify critical facilities and to work with critical facilities to assess backup power capabilities and provide resources where needed.[68] The proposed requirement that the utilities prioritize grid-based solutions over temporary backup generation to keep the essential businesses online is based on the utilities existing obligation to mitigate the impacts of de-energization events through system hardening and grid-based measures.[69] If a substation or circuit can safely remain energized, the entire community served by that infrastructure will be safer than if the critical facilities and business have to switch to backup power.

With stay-at-home orders in place, this is even more clear, as loss of service from these facilities, which have already been determined to be essential, will put residents at increased risk of exposure as they seek vital supplies in advance of an outage or after one takes place. In 2019, households that were notified of potential outages stripped store shelves of non-perishable food, batteries, flashlights, power decks for laptops and wireless phones, and other supplies, as residents sought to prepare for de-energization. After the power was restored, people again flocked to stores to restock. Now, during shelter-in-place orders, such runs on stores would increase risk of exposure, and the public's bulk-buying has strained supply chains for many stores. An extended de-energization event in these circumstances creates substantial

[68] D.19-05-042, pp. A11–A12.
[69] *Id.* at pp. A22–A23 (Reporting requirements 1 and 6).

risk, beyond that of a similar event without a concurrent pandemic. This means that awareness, analysis, and coordinated planning are critical.

As with proposed regulation No. 8 relating to Critical Treatment Facilities, the proposal relating to essential businesses does not, on its face, require the utilities to provide backup power to every essential business in their service territory.[70] And as with Critical Treatment Facilities, it is likely that a number of the businesses will have backup generation. Furthermore, many local governments and Community Choice Aggregators are developing their own resiliency infrastructure, which must be considered and optimally deployed during a de-energization event. The critical aspect of the regulation is partnership and planning, to avoid de-energization if possible, minimize the footprint if de-energization is necessary, and to limit the risks associated with de-energization for the affected communities. The proposed regulation requires p*artnership* with state agencies, local governments, and large customers to assess the facilities' resiliency; it requires *planning* to ensure the essential businesses that are within the area where de-energization cannot be avoided are able to remain energized; and it requires *working with* local governments and large customers to ensure the facilities receive any necessary temporary backup generation, and that local resiliency infrastructure is deployed in a rational manner.

11. Identification of Local Facilities Housing Vulnerable Populations and Serving as Shelters or Community Resource Centers

Proposed regulation No. 11, which requires utilities to keep a record of facilities identified by local governments that house vulnerable populations and/or might be used as evacuation shelters or Community Resource Centers that allow people to stay in separate rooms to maintain social distancing requirements, is an extension of the existing requirements that

[70] SDG&E Response, pp. 17–18; PG&E Response, pp. 19–20; SCE Response, pp. 8–9; TURN Response, pp. 4–7.

utilities work with local governments to identify critical facilities and to provide mitigations to impacted communities.[71] Mitigation to vulnerable populations is one of the most important aspects of de-energization, and it is an aspect on which the utilities have fallen significantly short of the mark.[72] While this has been an area of concern for AFN advocates and local governments even before the pandemic, the increased risk to vulnerable populations from COVID-19 raises the concerns yet further. The need for close coordination between utilities and local governments regarding Community Resource Centers (CRC), and the unsatisfactory results when the utilities fail to coordinate, are well-established in the record of this proceeding. To protect the people who are simultaneously at great risk of direct harm both from de-energization and from the coronavirus, all reasonable steps must be taken to identify these people and ensure they have a place of safety.

While the utilities have begun to reach out to some local governments to discuss CRC locations for the upcoming fire season, the Moving Parties have not seen the level of engagement contemplated by the proposed regulations. For example, PG&E has asked Santa Barbara County to sign contracts giving PG&E exclusive rights to the facilities the utility has identified for potential CRCs, because the utility will perform electrical upgrades; Santa Barbara County explained that it could not give PG&E exclusive rights because the facilities may also need to be used by the County as evacuation shelters or local assistance centers, and that PG&E must go through the County Emergency Operations Center (EOC) when making CRC siting

---

[71] D.19-05-042, p. A11; Resolution ESRB-8, p. 7.

[72] This Reply marks the latest in a long series of pleadings in this docket in which PG&E states that it is partnering with the California Foundation for Independent Living Centers and over 200 other community-based organizations to provide resources and mitigations for AFN individuals, to which the Center for Accessible Technology, the Joint Local Governments, and other stakeholders point out that PG&E has never provided any information about these partnerships that would allow the Commission, the parties, or the public understand whether the partnerships will actually provide benefits to AFN individuals or even what those benefits might be. (See PG&E Response, p. 8.)

decisions. Santa Barbara is willing to explore a co-location concept with PG&E, but the County's impression from that interaction is that this will be a difficult process. The Moving Parties also note that the separation between CRCs and evacuation shelters that SDG&E draws in its response does not reflect the reality of planning for and standing up either type of facility.[73] Finally, the Moving Parties appreciate the recommendations to local governments made by MGRA relating to wildfire safety during the COVID-19 pandemic.[74]

12. Telecommunications Infrastructure Resiliency

After reviewing the responses to proposed regulation No. 12, the Moving Parties agree that there are technical and logistical questions regarding the need for telecommunications resiliency, including backup power to support telecommunications facilities during an extended power outage, and that these questions are currently under review by the Commission in R.18-03-011.[75] However, it is still appropriate for the utilities to be required to partner with the telecommunications service providers, who are critical facilities, to assess the ability of their systems to maintain operations during de-energization events and to provide temporary backup generation if necessary.[76]

The proposed requirement for the utilities to work with local governments to develop plans for communicating and providing information to the public when communications networks go down remains appropriate for inclusion as an emergency regulation, as it is an extension of the existing requirement that the utilities develop a strategy, in coordination with

[73] SDG&E Response, p. 18.
[74] MGRA Response, pp. 8–9.
[75] See AT&T Response, pp. 4–5; CCTA Response, pp. 3–4; Consolidated Response, pp. 1–3; CTIA Response, pp. 3–4; Small LECs Response, pp. 2–3.
[76] D.19-05-042, p. A12.

public safety partners, for communication with customers recognizing that communication channels may be restricted due to loss of power.[77]

The proposed requirement that the utilities must notify local governments and public safety partners of telecommunications infrastructure located in the de-energization footprint, to the extent the utilities have that information, is simply a facet of the existing requirement that the utilities must identify critical facilities to public safety partners to allow those partners to prepare for de-energization.[78] The Moving Parties understand that the telecommunications providers consider their infrastructure location information to be confidential. However, the Commission has established existing rules governing utility provision of confidential information to public safety partners for de-energization planning and response purposes, and, to the extent the existing rules in this proceeding or R.18-03-011 do not cover critical telecommunications facility information, both PG&E and the Joint Local Governments have asked the Commission to clarify the confidentiality rules governing confidential critical facility and confidential customer information in the Phase 2 decision in this proceeding.[79]

13. Utility Claims Process for Financial Losses

Proposed requirement No. 13, which requires the utilities to develop a claims process for financial losses resulting from a de-energization during a declared state of emergency or shelter-in-place order, is an important part of mitigating the harms of de-energization during the COVID-19 pandemic. The 2019 de-energization events showed that an extended de-

[77] D.19-05-042, p. A19. SDG&E's ability to communicate with its public safety partners via satellite phones when telecommunications services are down is important, but it does not address the public's ability to communicate under the same circumstances. (SDG&E response, p. 19.)
[78] *Id.* at p. A15.
[79] PG&E Opening Comments on Proposed Additional and Modified De-Energization Guidelines, pp. 24–25 (February 19, 2020); Joint Local Governments' Reply Comments on Proposed Additional and Modified De-Energization Guidelines, pp. 23–26 (February 26, 2020).

energization event will cause widespread financial harm. Financial losses related to de-energization events are likely to be more acute during the pandemic because people's finances are already strained due to being laid off, working reduced hours or taking reduced pay, inability to send children to daycare, loss of school-provided meals for children, and other situations created by the need to shelter in place.

SDG&E states that it has an established claims process and that claims can be submitted through the utility's website.[80] But SDG&E then notes that claims for losses resulting from de-energization are presumptively invalid because de-energization is used as a last resort for safety.[81] PG&E's website also notes that the utility is generally not responsible for damages that result from power outages.[82] SCE, on the other hand, has instituted a temporary de-energization claims policy under which it will pay qualified spoilage claims for food and medication to eligible residential and business customers who did not receive at least 12 hours' notification of a de-energization event and who experienced a service interruption for more than eight hours.[83] The Moving Parties commend SCE for instituting this policy, despite its narrow applicability. While the broad issue of customer reimbursements for financial losses would appropriately be addressed further in the ongoing phases of this proceeding, it is appropriate for the utilities to assist customers already in crisis from the pandemic in order to ensure that they are not further subject to direct financial harm due to an extended power outage.

---

[80] SDG&E Response, p. 19.
[81] SDG&E Response, p. 19. See also MGRA Response, p. 7.
[82] https://www.pge.com/en_US/residential/customer-service/help/claims/claims.page (last visited April 23, 2020).
[83] https://www.sce.com/customer-service/request-support/claims?from=/claims (last visited April 23, 2020).

14. Residential Customer Bill Credits

Proposed regulation No. 14, which requires the utilities to automatically provide bill credits to customers impacted during a declared state of emergency or shelter-in-place order, without requiring them to go through a claims process, is a further effort to mitigate harms that households already under strain from the COVID-19 pandemic may experience as a result of de-energization. A household facing the dual crises of de-energization and pandemic may be at immediate risk of harm from food loss and inability to work (and be paid) without electricity. These households may be unable to readily go through a claims process, and they may need assistance as quickly as possible to make sure they have adequate access to healthy food. An automatic credit to ensure access to food will mitigate the harms and risks of households experiencing hunger due to the cascading pressures of pandemic, lost wages, lost food, and limited access to grocery stores. Without such support, the increased risk of hunger militates against any conclusion that an extended power outage supports public safety.

15. After-the-Fact Reasonableness Review

Proposed regulation No. 15, which specifically requires a reasonableness review by the Commission to evaluate compliance with the proposed emergency regulations, is an extension of the existing requirement that de-energization events be subject to a subsequent reasonableness review.[84] Given the increased public safety risks of de-energization during the COVID-19 pandemic, the Commission's post-event reasonableness review should examine the harms to public safety specific to COVID-19, in addition to the existing requirements. The Commission's review should be conducted within six months of the de-energization event and the results of the review should be made available to the public.

---

[84] D.12-04-024; Resolution ESRB-8, pp. 2, 4; D.19-05-042, p. A22.

The Moving Parties note that the existing requirement for post-event reasonableness review has not yet been fulfilled by the Commission. The Commission has made clear that the de-energization events of 2019 were not acceptable, and has initiated an Order to Show Cause in this proceeding against PG&E and opened an Investigation to examine whether the utilities adequately implemented the existing de-energization regulations in 2019, but these actions—while important—do not substitute for a timely reasonableness review of each de-energization event.[85] Review by the Commission of de-energization events is critical under any circumstance, but it is particularly important during the COVID-19 pandemic. To avoid repetition of the 2019 events, it is vital that the Commission convey clearly to the utilities that it will be reviewing the analysis they conducted to evaluate the balance of public safety before turning off the power and the effectiveness of coordination with local governments and public safety partners.

IV. CONCLUSION

As the Moving Parties stated at the outset of this reply, the responding parties' acknowledgment of the serious situation created by COVID-19 and the proposed clarifications and revisions to the emergency regulations are greatly appreciated. The Moving Parties also acknowledge that the large utilities have made improvements to their de-energization practices since the 2019 events, and the utilities' pledges to work more closely with their public safety partners regarding de-energization during this pandemic are both important and appreciated. But the fact remains that the Moving Parties—whose members are the very entities with whom the utilities claim to have improved relations to the point that additional regulations are unnecessary—believe that additional measures are necessary to ensure that the 2020 de-energization season does not exacerbate the public safety risks already created by the COVID-19

[85] See AT&T Response, pp. 5; MGRA Response, p. 7–8.

pandemic. The Moving Parties' members are on the front lines of the COVID-19 pandemic, wildfires, the utilities' de-energizations programs, and the de-energization events themselves. The Moving Parties ask that the Commission adopt the proposed emergency regulations.

Respectfully submitted April 24, 2020, at San Francisco, California.

LAW OFFICES OF MEGAN M. MYERS
Megan M. Myers
110 Oxford Street
San Francisco, California 94134
Telephone: (415) 994-1616
Email: meganmmyers@yahoo.com

By ________/s/Megan M. Myers___________
Megan M. Myers

Attorneys for California State Association of Counties

CENTER FOR ACCESSIBLE TECHNOLOGY
Melissa W. Kasnitz
3075 Adeline Street, Suite 220
Berkeley, California 94703
Telephone: (510) 841-3224
Email: service@cforat.org

By _____/s/Melissa W. Kasnitz_____________
Melissa W. Kasnitz

Attorneys for Center for Accessible Technology

CITY OF SAN JOSE
Richard Doyle, City Attorney
Yue-Han Chow, Senior Deputy City Attorney
Luisa F. Elkins, Senior Deputy City Attorney
Office of the City Attorney
200 East Santa Clara Street, 16th Floor
San Jose, California 95113-1905
Telephone: (408) 535-1201
Email: Yue-Han.Chow@sanjoseca.gov
Luisa.Elkins@sanjoseca.gov

By_____/s/ Luisa F. Elkins_____________
Luisa F. Elkins

Attorneys for City of San Jose

COUNTY OF SANTA CLARA
James R. Williams, County Counsel
Tiffany M. Lin, Deputy County Counsel
70 W. Hedding Street, Fl. 9
San Jose, California 95110
Telephone: (408) 299-5900
Email: tiffany.m.lin@cco.sccgov.org

By___/s/ Tiffany M. Lin______________
Tiffany M. Lin

Attorneys for County of Santa Clara

GOODIN, MACBRIDE,
SQUERI & DAY, LLP
Megan Somogyi
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
Email: msomogyi@goodinmacbride.com

By ___/s/Megan Somogyi___
Megan Somogyi

Attorneys for Counties of Kern, Marin, Mendocino, Napa, Nevada, San Luis Obispo, Santa Barbara, and Sonoma, and the City of Santa Rosa

EAST BAY COMMUNITY ENERGY
Melissa Brandt, Senior Director of Public Policy and Deputy General Counsel
1999 Harrison Street, Suite 800
Oakland, California 94612
Telephone: (510) 570-5110
Email: mbrandt@ebce.org

By ___/s/ Melissa Brandt___
Melissa Brandt

Attorneys for East Bay Community Energy

MARIN CLEAN ENERGY
Stephanie Chen, Senior Policy Counsel
1125 Tamalpais Avenue
San Rafael, California 94901
Telephone: (415) 464-6664
Email: schen@mcecleanenergy.org

By ___/s/ Stephanie Chen___
Stephanie Chen

Attorneys for Marin Clean Energy

BRAUN BLAISING SMITH WYNNE, P.C.
David Peffer
555 Capitol Mall, Suite 570
Sacramento, California 95814
Telephone: (616) 326-5812
Email: peffer@braunlegal.com

By ___/s/ David Peffer___
David Peffer

Attorneys for Marin Clean Energy and Peninsula Clean Energy

PIONEER COMMUNITY ENERGY
Jenine Windeshausen, Executive Director
2510 Warren Drive, Suite B
Rocklin, California 95677
Telephone: (279) 999-7011
Email:
regulatory@PioneerCommunityEnergy.ca.gov

By ___/s/ Jenine Windeshausen___
Jenine Windeshausen

Representatives for Pioneer Community Energy

RURAL COUNTY REPRESENTATIVES OF CALIFORNIA
Staci Heaton, Senior Regulatory Affairs Advocate
John Kennedy, Legislative Advocate
1215 K Street, Suite 1650
Sacramento, California
Telephone: (916) 447-4806
Email: sheaton@rcrcnet.org
jkennedy@rcrcnet.org

By ___/s/ Staci Heaton___
Staci Heaton

Advocates for Rural County Representatives of California

3759/008/X216395.v1

MAY FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Consider the Ratemaking and Other Implications of a Proposed Plan for Resolution of Voluntary Cases filed by Pacific Gas and Electric Company Pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088.	Investigation 19-09-016 (Filed September 26, 2019)

COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION APPROVING REORGANIZATION PLAN

Elizabeth M. Kelly
LAW OFFICE OF ELIZABETH KELLY
P.O. Box 225037
San Francisco, CA 94122
Telephone: (415) 535-9998
Email: beth@emk-law.com

Counsel for:
MARIN CLEAN ENERGY

May 11, 2020

TABLE OF CONTENTS

SUBJECT INDEX

Marin Clean Energy (MCE) generally supports the Proposed Decision, in particular the recognition that PG&E promises to do better tomorrow are insufficient. However, there are areas where the Proposed Decision should be modified. In these comments, MCE asks the Commission to:

- Adopt recommendations of Judge Alsup overseeing PG&E's felony probation to:
    - have the Commission and federal monitor meet with PG&E to determine how the Commission will guide the direction of the Safety Monitor;
    - establish an ongoing investigation intended to identify violations of vegetation and infrastructure management practices; and
    - condition PG&E management executive incentive compensation on meeting all wildfire abatement targets in the annual Wildfire Safety Plan;
- Adopt additional factors related to geographic residency for board selection to better align PG&E's board with the communities they serve;
- Direct PG&E to file a corrective action plan;
- Direct PG&E to file an application with a deleveraging plan to improve its financial condition more transparently;
- Limit financial waivers to effectuate specific provisions of PG&E's plan;
- Exclude customer program revenues from PG&E securitization;
- Reject PG&E's request to recover $154 million in financing-related costs from ratepayers;
- Rely on PG&E's equity backstop commitments to increase the level of equity contributions and reduce the amount of capital market financing required to emerge from bankruptcy; and
- Adopt several revisions to the Enhanced Oversight and Enforcement Process to clarify and improve certain procedural aspects.

TABLE OF AUTHORITIES

Statutes

Commission Decisions

Rules

Commission Proceedings

Hearing Transcripts

Court Orders

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Consider the Ratemaking and Other Implications of a Proposed Plan for Resolution of Voluntary Cases filed by Pacific Gas and Electric Company Pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088.	Investigation 19-09-016 (Filed September 26, 2019)

COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION APPROVING REORGANIZATION PLAN

Pursuant to Rule 14.3 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure Marin Clean Energy ("MCE") respectfully submits the following Comments on the Proposed Decision Approving Reorganization Plan mailed April 20, 2020 ("Proposed Decision"). Herein, MCE makes recommendations to refine the Proposed Decision in light of the record in this proceeding and the Order Modifying Conditions of Probation issued by Federal Judge William Alsup on April 29, 2020.[1]

The Proposed Decision relies upon PG&E to "make good" upon its promises, without making those promises enforceable commitments. The Proposed Decision itself declares that the

[1] Order Modifying Conditions of Probation, *United States of America v. Pacific Gas and Electric Company*, April 29, 2020, No. CR 12-0175 WHA (N.D. Cal.). Available at: https://www.courthousenews.com/wp-content/uploads/2020/04/pge-probation-ruling.pdf.

Commission "has lost patience with PG&E's incessant but unfulfilled promises to do better tomorrow."[2] MCE recommends enforceable commitments below, particularly as they relate to safety and finances.

I. SAFETY, GOVERNANCE STRUCTURE AND CRIMINAL PROBATION

The Commission is accurate in its observations about PG&E and its safety challenges:

> It is understandable that PG&E may want to shift the focus away from the history of its recent safety performance - which has ranged from dismal to abysmal - and instead seek to draw attention to its remedial efforts. At the same time, however, this is a cause for concern, as PG&E seems reluctant to take ownership of its own safety history and acknowledge its failings.[3]

The Commission's observations are echoed by the findings of Judge Alsup in PG&E's federal criminal probation proceeding:

> A fundamental concern in this criminal probation remains the fact that Pacific Gas & Electric Company, though the single largest privately-owned utility in America, cannot safely deliver power to California. This failure is upon us because for years, in order to enlarge dividends, bonuses, and political contributions, PG&E cheated on maintenance of its grid — to the point that the grid became unsafe to operate during our annual high winds, so unsafe that the grid itself failed and ignited many catastrophic wildfires.[4]

MCE makes recommendations to align regulation of PG&E's safety with what is warranted from its unsafe and damaging history.

A. Independent Safety Advisor

MCE supports the Commission's direction to utilize a Safety Monitor. The Commission's direction has also received support from Judge Alsup:

> The Court notes with approval the order of the CPUC Administrative Law Judge Peter Allen requiring that PG&E hire an independent monitor to continue what the federal monitor has been doing, keeping in mind the fact that the federal monitorship will end in 19 months [January 2022, which can't be extended] when

[2] Proposed Decision at 51.
[3] Proposed Decision at 15-16.
[4] Alsup Order at 1.

> probation ends. The Court believes it would be productive for the CPUC and the federal monitor to meet with PG&E to devise ways to carry out the new conditions set forth above.[5]

MCE asks the Commission to implement the recommendation of Judge Alsup to have the Commission and federal monitor meet with PG&E to determine how the Commission will guide the direction of the Safety Monitor. Consistent with this approach, MCE recommends a modification to Ordering Paragraph 8 as follows:

> **<u>Pursuant to the direction to be given by the Commission and the federal monitor to Pacific Gas and Electric Company,</u>** Pacific Gas and Electric Company shall submit a Tier 3 Advice Letter to the Commission's Energy Division no later than one year before the expiration of the term of the federal court monitor, with a proposed scope of work, budget, solicitation process for an Independent Safety Monitor, and a process for selection/approval by the Commission. Energy Division will process the Tier 3 Advice Letter in consultation with the Commission's Safety Enforcement Division and Safety Policy Division, as appropriate.

B. Board of Directors and Holding Company

1. Composition of the Boards of Directors

MCE supports the Commission's adoption of "an initial formulation of a minimum of 50% of board members being residents of California, with a preference for those living in PG&E's service territory"[6] MCE also supports the Commission overseeing the PG&E board member selection process for a period of seven years, extended if PG&E has not met the criteria set forth by the TCC.[7] MCE also recommends the Commission adopt additional factors for weighing candidates related to geographic residency including: (1) residing in a disadvantaged community as defined by the top 25% of the CaEnviroScreen 3.0 list; (2) residing in a

[5] Alsup Order at 12.
[6] Proposed Decision at 29.
[7] The Criteria are: "(1) PG&E's culture has changed dramatically, (2) its safety and operational history has been exemplary for such a long period that it is indisputable that it has overcome the strong presumption against it from its past record, and (3) it has controls and other safeguards in place to ensure it does not slip back into old habits." Proposed Decision at 34.

community that has been damaged by a utility-caused wildfire; and (3) residing in a community that has been impacted by a Public Safety Power Shutoff. While these factors should not be prerequisites for board service, PG&E should be encouraged to weigh them heavily in their selection process. These factors will help align board representation with the interests of the communities PG&E serves.

2. *Holding Company [No Heading in Proposed Decision, but Discussed Here]*

MCE supports the Commission taking a hard look at PG&E's holding company. MCE agrees that "the operational value of a holding company structure for PG&E at this time is at best questionable."[8] So long as the elimination of PG&E's holding company structure is considered within the Safety OII, MCE does not oppose the overlap of the board members of PG&E Company and PG&E Corporation at this time.

C. Fines and Penalties

MCE strongly supports the Commission order for PG&E to "modify the plan to state that neither confirmation nor consummation of the plan shall affect any pending or future Commission proceeding or investigation, including any adjudication or disposition thereof, and any liability of the Debtors or Reorganized Debtors, as applicable, arising therefrom shall not be discharged, waived, or released."[9] Neither this Commission nor the Bankruptcy Court should allow for the excessively broad exculpations and releases set forth by PG&E in its plan. The Commission should adopt policies for safety-related fines or penalties to: (1) direct substantial portions to remedy

---

[8] Proposed Decision at 37.
[9] Proposed Decision at 44-45.

safety-related harms or risks to communities; and (2) avoid creating tax benefits that would reduce the deterrent effect of fines or penalties.

D. Enhanced Oversight and Enforcement Process

MCE supports increased oversight of PG&E, including the Oversight and Enforcement Process as set forth in the Proposed Decision. However, MCE makes limited recommendations, attached as Appendix B, to improve Commission oversight and enforcement.

Every step of the Enhanced Oversight and Enforcement Process requires a safety corrective action plan (CAP) to be submitted by PG&E. There is no doubt that a CAP is needed regardless of which step PG&E is currently in. The Commission should direct PG&E to file a CAP via a Tier 3 Advice Letter within 30 days of issuance of the Decision.

The Commission should adopt the recommendation of Judge Alsup to take strong action on oversight and enforcement to make Northern California safer from PG&E's actions:

> Utilities should be fined for violating vegetation management and infrastructure remediation requirements. PG&E does not currently face punishments for these violations of California law. The state could impose harsher penalties for PG&E's failure to maintain proper vegetation clearances, including failure to mitigate hazard trees and limbs within a reasonable period of time, and impose harsher penalties for PG&E's failure to address infrastructure remediation tags within regulatory time frames. The state could consider a regulatory-based penalty proceeding, relying on sheriffs, the Highway Patrol, CAL FIRE, and so on to flag violations for the CPUC to investigate.[10]

To effectuate this recommendation, the Commission should establish an ongoing investigation intended to identify violations of vegetation and infrastructure management practices. This could be accomplished through regular successor proceedings, but the Commission should attempt to preserve the record through time to examine trends of improvement or decline in performance.

[10] Alsup Order at 12.

II. FINANCIAL

A. PG&E's Financing Request [No Heading in Proposed Decision, but Discussed Here]

1. The Commission's Substantial Financial Concessions to PG&E Should Be Contingent Upon an PG&E Submitting an Application for Approval of a Deleveraging Plan

Without discussion, the Commission approves PG&E's debt requests – including their many objectionable provisions[11] – totaling $23.775 in long-term debt and additional $2 billion in short term debt authorization.[12] The Commission approves a waiver to PG&E's capital structure for five years with the sole requirements of filing a periodic Tier 1 Advice Letter and, <u>in five years' time</u>, file an application for deleveraging the company. The Commission also grants an increase in PG&E's temporary debt authorization solely through an indirect reference in Conclusion of Law 7. All of these are substantial concessions by the Commission to PG&E to allow them emerge from bankruptcy – and none of these are contingent upon meaningful change or corrective action by PG&E.

MCE recommends the Commission improve the oversight of PG&E's financial stability and financial plan by directing PG&E to file an Application within 60 days of this Decision setting forth its deleveraging plan. The Application should include PG&E's plan to:

- Come into compliance with its capital structure requirements;
- Return to the temporary debt limit set forth in D.09-05-002 subject to the conditions set forth therein;[13]
- Offset ratepayer impacts associated with an overleveraged capital structure.

---

[11] See, MCE Brief at 33 *et seq.*, which discusses PG&E's violation of Section 701.5, use of cross-default and prepayment provisions excessively tying the Company and the Corporation, and securing debt that was previously unsecured.
[12] Proposed Decision at 65.
[13] See discussion at MCE Brief at 23.

2. *MCE Supports the Recommendation of the Tort Claimants Committee to Clarify that Any Commission Financial Waiver Is Limited*

MCE also supports the recommendation of the Tort Claimants Committee (TCC) that the financial waivers set forth in the Proposed Decision be clarified such that any "waiver only applies to the extent necessary to implement specific provisions of the Plan that have been reviewed and approved by the Commission and the Bankruptcy Court."[14]

B. Securitization

The Proposed Decision fails to include direction regarding the securitization as requested by MCE, specifically:

> "As committed by PG&E in hearings, the Commission should ensure that any securitization proposal exclude CCA revenues and other excluded revenues consistent with the Final Order regarding Customer Programs, including Pubic Purpose Programs. These Customer Programs are defined in the associated Motion of the Debtors, and include (i) Deposit and Reimbursement Programs, (ii) Public Purpose Programs, (iii) Environmental Cleanup Programs, (iv) Third-Party Programs, which includes CCA, (v) GHG Credit Programs, and (vi) Customer Support Programs. The Commission should issue an order to ensure PG&E will not pledge these revenues as security for debt."[15]

This commitment was made under oath by PG&E[16] and should be included in the Decision. Committing PG&E to its promises is not simply a "belt and suspenders" exercise. On April 30, 2020, PG&E submitted its Application for securitization.[17] The securitization Application does not include the carve-outs committed to by PG&E in this proceeding. This is no mere mistake. The same counsel on behalf of PG&E who defended the witness in question is the same lead counsel on behalf of PG&E in the securitization Application.

---

[14] TCC Opening Comments on Proposed Decision at 13.
[15] MCE Brief at 40-41 [Citations Omitted].
[16] Wells (PG&E), Hearing Transcript Vol. 4 (February 28, 2020) at 520 line 26.
[17] A.20-04-023.

The securitization Application itself should raise significant questions and concerns of the Commission, including PG&E's failure – again – to provide for a "Plan B." In this Proceeding, PG&E has only offered a "Plan A" for its emergence from bankruptcy and rejected all opportunities to consider a "Plan B" that would better serve the public interest. The Commission must direct PG&E to provide clear options to the Commission, rather allowing PG&E to proffer the sole option of securing the highest value asset of PG&E – its ratepayer revenue – for the benefit of shareholders.

C. Contributions of Ratepayers

As the Proposed Decision notes, PG&E's overleveraged capital structure is and will continue to have negative ratepayer impacts.[18] As set forth above, PG&E should immediately – not five years from now – file a financial deleveraging plan via Application. This improve transparency and give ratepayers and the public greater confidence that PG&E is on a path to financial health.

MCE further recommends rejection of PG&E's request for $154 million in financing-related costs.[19] These costs are part of PG&E's comprehensive Plan to address its own excessive shareholder liabilities. This amount should not be extracted from ratepayers while they are already bearing the risks of PG&E's financially precarious position post-emergence and contributing over $6 billion to the Wildfire Fund as a result of PG&E's Plan.

D. Financial Condition and Capital Structure

PG&E's financial condition will be weak upon emergence. PG&E will not be in compliance with its capital structure requirements and will be required to provide collateral for all

---

[18] Proposed Decision at 83.
[19] Proposed Decision at 71.

new debt in order to get better-than-junk-bond ratings. Each of these are profoundly concerning and do not position PG&E well in the event of another catastrophic fire or a pandemic-related economic downturn.

The Proposed Decision relies upon the five-year "business plan" of PG&E and "the various statements [PG&E has made] to indicate it will seek to improve its credit ratings and underlying credit profile following its emergence from Chapter 11."[20] The Commission cannot rely upon PG&E's "statements" and PG&E's "every intention of doing its best."[21] While much more could be done by the Commission to ensure that PG&E improves its financial condition, MCE recommends that the Commission: (1) adopt TURN's proposal to infuse more equity into PG&E by relying on equity backstop commitments to reduce capital market borrowing by approximately $3 billion, and (2) direct PG&E to file an Application within 60 days of this Decision setting forth its deleveraging plan as discussed above.

E. Executive Compensation

While the Commission proposes to allow for PG&E's executive compensation plan subject to Commissioner Proposal 9, MCE recommends further work must be performed, including a greater emphasis on safety. As stated by Judge Alsup:

"[E]xecutive bonuses should be tied to safety management. Mid- and senior-level executives at PG&E should be paid out on their yearly bonuses on the condition that PG&E met all of its wildfire abatement targets in the annual Wildfire Safety Plan. Had this policy been in effect last year, bonuses would hypothetically not have been distributed, because PG&E reported meeting only 46 of their 53 internal safety targets."[22]

---

[20] Proposed Decision at 80.
[21] PG&E Reply Brief at 14.
[22] Alsup Order at 12-13.

MCE recommends that the Commission incorporate this recommendation into Commissioner Proposal 9.

III. COMMISSION BANKRUPTCY COSTS

The Commission's recovery of bankruptcy costs is consistent with past precedent.[23] MCE supports the proposal.

IV. OTHER PROPOSALS AND RELATED PROCEEDINGS

MCE supports the Proposed Decision's "disposition of proposals for certain potential changes to the Utility's corporate structure and authorizations to operate as a utility," under Section 1.38 (Section 1.37) of the Amended Plan of Reorganization."[24] The Safety OIR is an essential venue for considering important changes to improve the safety and finances of PG&E, including through revocation of the holding company status of PG&E and transitioning PG&E to a "wires only" electric utility to improve its operational focus and financial health.

V. CONCLUSION

MCE thanks President Batjer and Administrative Law Judge Allen for their thoughtful consideration of these important matters and requests adoption of the recommendations set forth by MCE herein.

---

[23] D.03-12-035 at 18.
[24] Proposed Decision at 99.

Respectfully submitted,

/s/ Elizabeth Kelly
Elizabeth M. Kelly
LAW OFFICE OF ELIZABETH KELLY
P.O. Box 225037
San Francisco, CA 94122
Telephone: (415) 535-9998
Email: beth@emk-law.com

Counsel for:
MARIN CLEAN ENERGY

May 11, 2019

APPENDIX A

PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

Findings of Fact:

New FOF: "PG&E's recent safety performance has ranged from dismal to abysmal." [25]

New FOF: "PG&E has not taken adequate ownership of its own safety history or acknowledged its failings."[26]

New FOF: The Commission must keep a close watch on PG&E's financial condition, given its importance for both PG&E and its customers.[27]

New FOF: PG&E committed in hearings that any securitization proposal would exclude revenues associated Customer Programs, including Pubic Purpose Programs, defined in Final Order regarding Customer Programs, including Pubic Purpose Programs [Bankruptcy Dkt. 843].

Conclusions of Law:

Ordering Paragraphs:

OP 8: **Pursuant to the direction to be given by the Commission and the federal monitor to Pacific Gas and Electric Company,** Pacific Gas and Electric Company shall submit a Tier 3 Advice Letter to the Commission's Energy Division no later than one year before the expiration of the term of the federal court monitor, with a proposed scope of work, budget, solicitation process for an Independent Safety Monitor, and a process for selection/approval by the Commission. Energy Division will process the Tier 3 Advice Letter in consultation with the Commission's Safety Enforcement Division and Safety Policy Division, as appropriate.

New OP: Within 30 days of issuance of this Decision, Pacific Gas and Electric Company is directed to file a safety corrective action plan.

[25] Proposed Decision at 16.
[26] Proposed Decision at 16.
[27] Proposed Decision at 82.

New OP: Within 60 days of issuance of this Decision, Pacific Gas and Electric Company is directed to file an application that shall include a deleveraging proposal to reduce non-traditional utility debt over time. The application shall include proposals to offset ratepayer impacts associated with an overleveraged capital structure.[28] Failure to comply with such plan shall be considered a contribution of ratepayers and result in appropriate compensation to ratepayers.

New OP: Pacific Gas and Electric Company shall exclude from any securitization proposal any revenues associated Customer Programs, including Pubic Purpose Programs, defined in Final Order regarding Customer Programs, including Pubic Purpose Programs [Bankruptcy Dkt. 843].

---

[28] Proposed Decision at 83.

APPENDIX B

REVISIONS TO ENHANCED OVERSIGHT AND ENFORCEMENT PROCESS

STEP 1: Enhanced Reporting

A. Triggering Events

i. PG&E fails to obtain an approved wildfire mitigation plan or fails in any material respect to comply with its regulatory reporting requirements.

ii. PG&E fails to comply with, or has shown insufficient progress toward, any of the metrics (i) set forth in its approved wildfire mitigation plan including Public Safety Power Shutoffs (PSPS) protocols, (ii) resulting from its on- going safety culture assessment, (iii) contained within the approved Safety and Operational Metrics, or (iv) related to other specified safety performance goals.

iii. PG&E demonstrates insufficient progress toward approved safety or risk- driven investments related to the electric and gas business.

iv. PG&E (or PG&E Corporation) fails in any material respect to comply with the Commission's requirements and conditions for approval of its emergence from bankruptcy.

B. Actions During Step 1

PG&E will submit a Corrective Action Plan ~~**to the Executive Director**~~ **via a Tier 2 Advice Letter** within twenty days of a Commission Order placing PG&E into Step 1.

i. The Corrective Action Plan shall be designed to correct or prevent a recurrence of the Step 1 triggering event, or otherwise mitigate an ongoing safety risk or impact, as soon as practicable and include an attestation stating that it has been approved by the Chief Risk Officer (CRO).

ii. The Corrective Action Plan, including any timeframes set forth therein for the correction of the triggering events or mitigation of any ongoing safety risk or impact, shall be approved by the Commission or the Executive Director.

iii. Commission staff will monitor PG&E's compliance with its Corrective Action Plan based on, among other things, existing or enhanced reporting.

iv. The CRO, the Safety and Nuclear Oversight (SNO) Subcommittee, and the boards of directors shall provide reporting to the Commission as directed.

C. Performance that Results in Exit from Step 1

i. PG&E shall exit from Step 1 of the Process upon issuance of a Commission Resolution finding that PG&E has met the conditions of its Corrective Action Plan within the required timeframe.

ii. The Commission, by Resolution, will move PG&E to Step 2 if it fails to adequately meet the conditions of its Corrective Action Plan within the required timeframe. PG&E may remain in Step 1 if it demonstrates sufficient progress toward meeting the conditions of its Corrective Action Plan and additional time appears needed to successfully address the triggering event(s).

Step 2: Commission Oversight of Management and Operations

A. Triggering Events

i. PG&E fails to adequately meet the conditions of its Corrective Action Plan within the required timeframe as provided in Step 1, Section C (ii) above.

ii. A gas or electric incident occurs that results in the destruction of 1,000 or more dwellings or commercial structures and appears to have resulted from PG&E's failure to follow Commission rules or orders or prudent management practices.

iii. PG&E fails to comply with electric reliability performance metrics, including standards to be developed for intentional de-energization events (i.e., PSPS) and any that may be contained within the approved Safety and Operational Metrics.

iv. PG&E fails to report to the Commission a systemic electric or gas safety issue.

B. Actions During Step 2

i. PG&E will submit a Corrective Action Plan, or updated Corrective Action Plan, ~~**to the Executive Director**~~ **via a Tier 3 Advice Letter** within twenty days of a Commission Order placing PG&E into Step 2.

ii. The Corrective Action Plan shall be designed to correct or prevent a recurrence of the Step 2 triggering event, or otherwise mitigate an ongoing safety risk or impact, as soon as practicable and shall include an attestation stating that it has been approved by the CRO and the SNO Subcommittee.

iii. The Corrective Action Plan, including any timeframes set forth therein for the correction or prevention of the Step 2 triggering events or mitigation of any ongoing safety risk or impact, shall be approved by the Commission or the Executive Director.

iv. Commission staff will monitor PG&E's compliance with its Corrective Action Plan based on, among other activities, increased inspections, quarterly reports, and, to the extent applicable, spot auditing of General Rate Case, Wildfire Expense Memorandum Account, Catastrophic Events Memorandum Account, or Pipeline Safety Enhancement Plans accountsin which approved investments in wildfire mitigation, electric or gas safety are auditable.

v. A representative of the SNO Subcommittee and the CRO shall appear quarterly before the Commission to report progress on the Corrective Action Plan and provide additional reporting as directed.

C. Performance that Results in Exit from Step 2

i. PG&E shall exit from Step 2 upon issuance of a Commission Resolution finding that the company has met the conditions of its Step 2 Corrective Action Plan within the required timeframe. The Commission may move PG&E back to Step 1 of the Process rather than exit the process if it determines that PG&E has made sufficient progress in meeting its Step 2 Corrective Action Plan but continued enhanced reporting is needed.

ii. The Commission, by Resolution, will move PG&E to Step 3 if PG&E fails to adequately meet the conditions of its Corrective Action Plan and additional time in Step 2 is not likely to result in the effective implementation of its Corrective Action Plan.

Step 3: Appointment of Independent Third-Party Monitor

D. Triggering Events

i. **A gas or electric incident occurs that results in the destruction of 10 or more dwellings or commercial structures and appears to have resulted from PG&E's failure to follow Commission rules or orders or prudent management practices.**

ii. PG&E fails to adequately meet the conditions of its Corrective Action Plan within the required timeframe, as provided in Step 2, Section C (ii).

iii. PG&E fails to obtain or maintain its safety certificate as provided in AB 1054.

E. Actions During Step 3

i. **The Commission shall launch an Order Instituting Investigation to determine appropriate conditions, if any, to be applied to PG&E's CPCN and to evaluate revisions to PG&E's Corrective Action Plan.**

ii. The Commission's Executive Director ~~**may**~~ **shall** appoint an independent third-party monitor (Monitor), or **may** expand the authority of any Independent Safety Monitor previously appointed by the Commission, to oversee PG&E's operations and to work with senior management to develop and implement a Corrective Action Plan with reasonable timeframes to address the triggering event(s) as soon as practicable.

iii. The Monitor will provide active, external oversight of PG&E's implementation of its Corrective Action Plan.

iv. The Monitor will have the authority to hire third-party safety and utility operations experts to assist it with its oversight obligations.

v. PG&E's senior management must work jointly with the Monitor to develop and implement a Corrective Action Plan including reasonable timeframes (which timeframes shall be acceptable to the Commission). The Corrective Action Plan shall be certified by the Monitor.

vi. PG&E may request the Monitor to modify the Corrective Action Plan but must otherwise implement the plan as approved by the Monitor.

vii. The Monitor will provide quarterly reports to the Commission and to PG&E's board of directors on the progress towards implementing the Corrective Action Plan.

viii. The CRO and SNO Subcommittee will provide reporting to the Commission as required during this Step.

F. Performance that Results in Exit from Step 3

i. PG&E shall exit from Step 3 upon issuance of a Commission Resolution finding that PG&E has met the conditions of its Step 3 Corrective Action Plan within the required timeframe. The Commission may determine that PG&E must remain in Step 1 or 2 for additional time after it confirms that PG&E has exited Step 3.

ii. The Commission, by Resolution, will move PG&E to Step 4 if any of the following occurs:

a. PG&E fails to implement the Corrective Action Plan within the timeframes required by the Monitor or the Commission's Executive Director.

b. The Commission determines that additional enforcement is necessary because of PG&E's systemic non-compliance or poor performance with its Safety and Operational Metrics over an extended period.

Step 4: Appointment of a Chief Restructuring Officer

A. Triggering Events

i. PG&E fails to adequately meet the conditions of its Corrective Action Plan within the required timeframe and additional time in Step 3 is not likely to result in the effective implementation of its Corrective Action Plan, as provided in Step 3, Section C (ii)(a).

ii. Additional enforcement is necessary because of PG&E's systemic non-compliance or poor performance with its Safety and Operational Metrics over an extended period.

iii. The Commission determines through an Order to Show Cause, Order Instituting Investigation, or other appropriate process, that PG&E repeatedly violated its regulatory requirements, committed gross negligence, or committed a serious violation of the law, such that such conduct in the aggregate represents a threat to public health and safety.

iv. PG&E causes an electric or gas safety incident that results in the destruction of 1,000 or more dwellings or commercial structures and the Commission determines through an Order to Show Cause, Order Instituting Investigation, or other appropriate process, that such event results from the willful misconduct or repeated and serious violations of Commission rules, orders or regulatory requirements.

v. The Commission determines through an Order to Show Cause, Order Instituting Investigation, or other appropriate process that additional enforcement is necessary because the wildfire fund administrator has made a determination following a covered wildfire that PG&E is ineligible for the cap on reimbursement because its actions or inactions that resulted in a covered wildfire constituted conscious or willful disregard of the rights and safety of others.

vi. PG&E failed to obtain or maintain its safety certificate as provided in AB 1054 for a period of three consecutive years.

B. Actions During Step 4

i. <u>The Commission will implement appropriate conditions on PG&E's CPCN.</u>

ii. <u>The Commission will develop a contingency plan in the event of a revocation of PG&E's CPCN.</u>

iii. The Commission will require that PG&E retain a chief restructuring officer from a list of qualified candidates identified by a third-party. The chief restructuring officer will have full management responsibility for developing and directing PG&E to implement the Corrective Action Plan with reasonable timeframes to address the triggering event(s) as soon as practicable.

iv. The chief restructuring officer will have the authority of an executive officer of PG&E and will report to the SNO Committee on all safety issues.

v. PG&E's senior management must work jointly with the chief restructuring officer to develop and implement a Corrective Action Plan including reasonable timeframes (which timeframes shall be acceptable to the Commission).

vi. The chief restructuring officer will have all corporate authority that can be delegated to an officer under the California Corporations Code in order to ensure that PG&E can meet its Corrective Action Plan.

vii. The Corrective Action Plan must be certified by the chief restructuring officer.

viii. PG&E must otherwise implement the Corrective Action Plan as certified by the chief restructuring officer.

ix. The chief restructuring officer will provide quarterly reports to the Commission and to PG&E's board of directors on the progress towards implementing the Corrective Action Plan.

x. The Chief Restructuring Officer will remain in place during Steps 5 and 6, if triggered.

C. Performance that Results in Exit from Step 4

i. PG&E shall exit from Step 4 upon issuance of a Commission Resolution finding that it met the conditions of its Step 4 Corrective Action Plan within the required timeframe. The Commission may determine that PG&E must remain in Steps 1, 2, or 3 for additional time after PG&E has exited Step 4.

ii. The Commission by Resolution will move PG&E to Step 5 if the Commission finds that PG&E failed to implement the Corrective Action Plan within the timeframes required by the chief restructuring officer or the Commission.

iii. PG&E may remain in Step 4 if the Commission determines that additional time appears needed to successfully address the triggering event(s).

Step 5: Appointment of a Receiver

A. Triggering Events

  i. PG&E fails to implement its Step 4 Corrective Action Plan within the required timeframes, as provided in Step 4, Section C (ii).

B. Process

  i. The Commission will pursue the receivership remedy subject to then applicable law of the state of California. If PG&E becomes the subject of a subsequent chapter 11 case, PG&E will agree not to dispute the Commission's or state of California's authority to file a motion for the appointment of a chapter 11 trustee.

  ii. The receiver, if appointed by the Superior Court, would be empowered to control and operate PG&E's business units in the public interest but not dispose of the operations, assets, business or PG&E stock.

C. Performance that Results in Exit from Step 5

  i. If the Commission by Resolution determines that PG&E has corrected all of the Step 5 triggering events and has remained in material compliance with Safety and Operational Metrics for a period of 18 months, the Commission may request termination of any receivership. At any time while the receiver is in place and to the extent permitted by then applicable law, the Commission can initiate a Step 6 enforcement action if a Step 6 triggering event has occurred.

  ii. In the event that the Commission seeks, but is not successful in obtaining a receiver, the Commission would determine whether PG&E shall remain in Step 4 or advance to Step 6.

Step 6: Review of CPCN

A. Triggering Events

  i. A receiver appointed as set forth above has determined that continuation of Receiver Oversight will not result in restoration of safe and reliable service; provided that such receiver shall have been a place for a period of at least nine (9) months before making such a determination.

  ii. A court of applicable jurisdiction has denied the Commission's request for a receiver made as set forth above.

  iii. PG&E fails adequately to address all of the Step 5 triggering events within 18 months of imposition of Step 5 and the Commission determines that additional time in Step 5 is unlikely to result in corrective action.

B. Process

  i. The Commission will undertake this process subject to then applicable law of the state of California.

  ii. The CPUC will issue an order to show cause or Order Instituting Investigation to initiate Step 6

iii. As a result of the order to show cause, the CPUC may place **<u>additional conditions</u>** on PG&E's CPCN or revoke PG&E's CPCN.

May 7, 2020

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Advice Letter 42-E

RE: Establish and Implement the Disadvantaged Communities Green Tariff Program Rate and the Community Solar Green Tariff Program Rate

Pursuant to Ordering Paragraph ("OP") 17 of Decision ("D.")18-06-027 *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities* and Resolution E-4999, MCE hereby submits this Advice Letter ("AL") to establish and implement the Disadvantaged Community Green Tariff ("DAC-GT") and the Community Solar Green Tariff ("CS-GT") programs.

TIER DESIGNATION

This AL has a Tier 3 designation pursuant to OP 17 of D.18-06-027.

EFFECTIVE DATE

Pursuant to General Order 96-B, this Tier 3 AL will become effective when the Commission adopts a resolution approving the advice letter.

BACKGROUND

On June 21, 2018, the California Public Utilities Commission ("Commission" or "CPUC") approved of D.18-06-027, adopting three new programs to promote the installation of renewable generation among residential customers in disadvantaged communities ("DAC"),[1] as directed by the California Legislature in Assembly Bill (AB) 327(Perea), Stats. 2013, ch 611. The three programs include the DAC Single Family Solar Homes ("DAC-SASH") program, which provides up-front incentives for the installation of solar at low-income homes in DACs. The other two programs, the DAC-GT and the CS-GT programs are community solar programs which offer 100% solar energy to customers and provide a 20% discount on the electric portion of the bill.

Community Choice Aggregators ("CCAs") may develop and implement their own DAC-GT and CS-GT programs. CCA programs and tariffs must abide by all program rules and requirements

[1] DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen 3.0 as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data.

adopted in D.18-06-027. This Decision also provides that CCAs must file a Tier 3 AL to implement the CCA DAC-GT and CS-GT programs;[2] Resolution E-4999 provides that such AL must be filed on or before January 1, 2021.[3]

PURPOSE

MCE files this Tier 3 AL to create DAC-GT and CS-GT programs and tariffs consistent with all provisions in D.18-06-027, D.18-10-007,[4] Resolution E-4999, as well as guidance received from the Commission's Energy Division.

The following Appendices are attached to this Advice Letter:

1. Appendix A: Implementation Plan for the DAC-GT and CS-GT programs;

2. Appendix B: Schedule DAC-GT, *Disadvantaged Community Green Tariff Program* and Schedule CS-GT, *Community Solar Green Tariff Program*;

3. Appendix C: Program budgets for program years ("PYs") 2020 and 2021;

4. Appendix D: Marketing, education and outreach ("ME&O") plan for PYs 2020 and 2021;

MCE respectfully requests the Commission approve MCE's program implementation plan, tariff sheets, and ME&O plan for the DAC-GT and CS-GT programs as described in the attached documents. Furthermore, MCE requests that the Commission approve the proposed budgets for PYs 2020 and 2021 as detailed in Appendix C and direct PG&E to

(1) modify its DAC-GT and CS-GT balancing accounts to include a sub-account to track the funding and costs of MCE's DAC-GT and CS-GT programs;

(2) include the total forecasted budget request for PYs 2020 and 2021 for MCE's DAC-GT and CS-GT programs in its 2021 ERRA filings;

(3) upon approval of the 2021 ERRA Forecast, transfer program funds for the 2021 PY to MCE in four quarterly installments (by January 1, April 1, July 1 and October 1 of each year) for the upcoming quarter. For 2020 program funds, PG&E must transfer all past due funds within thirty days of approval of the 2021 ERRA Forecast filing.

CONCLUSION

MCE respectfully requests the Commission approve the implementation details and budgets proposed by MCE to establish and implement the DAC-GT and the CS-GT programs.

---

[2] D.18-06-027, at p.104 (OP 17).
[3] Resolution E-4999 at p.16.
[4] D.18-10-007, *Decision Correcting and Clarifying Decision 18-06-027*, from 10/18/2018.

NOTICE

A copy of this AL is being served on the official Commission service lists for Rulemaking R.14-07-002.

For changes to this service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

PROTESTS

Anyone wishing to protest this advice letter filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

> CPUC, Energy Division
> Attention: Tariff Unit
> 505 Van Ness Avenue
> San Francisco, CA 94102
> Email: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Deputy Executive Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should be sent by letter or transmitted electronically to the attention of:

> Jana Kopyciok-Lande
> Senior Policy Analyst
> Marin Clean Energy
> 1125 Tamalpais Ave
> San Rafael, CA 94901
> Email: jkopyciok-lande@mcecleanenergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

CORRESPONDENCE

For questions, please contact Jana Kopyciok-Lande at (415) 464-6044 or by electronic mail at jkopyciok-lande@mceCleanEnergy.org.

/s/ Jana Kopyciok-Lande

Jana Kopyciok-Lande
Senior Policy Analyst
MARIN CLEAN ENERGY

cc: Service List: R.14-07-002

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Jana Kopyciok-Lande
Phone #: (415) 464-6044
E-mail: jkopyciok-lande@mcecleanenergy.org
E-mail Disposition Notice to: jkopyciok-lande@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 40-E

Tier Designation: 1

Subject of AL: To provide a rationale for including rebates that exceed measure costs in the 2020 ABAL filing.

Keywords (choose from CPUC listing):

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
N/A

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information: N/A
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date:

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Name: Jana Kopyciok-Lande
Title: Senior Policy Counsel
Utility Name: Marin Clean Energy
Address: 1125 Tamalpais Ave
City: San Rafael
State: California Zip: 94901
Telephone (xxx) xxx-xxxx: 415-464-6044
Facsimile (xxx) xxx-xxxx: 415-459-8095
Email: jkopyciok-lande@mcecleanenergy.org

Name: Alice Havenar-Daughton
Title: Director of Customer Programs
Utility Name: Marin Clean Energy
Address: 1125 Tamalpais Ave
City: San Rafael
State: California Zip: 94901
Telephone (xxx) xxx-xxxx: 415-464-6030
Facsimile (xxx) xxx-xxxx: 415-459-8095
Email: ahavenar-daughton@mceCleanEnergy.org

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

APPENDIX A

Implementation Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs

Proposed by Marin Clean Energy

Alice Havenar-Daughton
Director of Customer Programs
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
E-mail: ahavenar-daughton@mcecleanenergy.org

May 7, 2020

TABLE OF CONTENTS

1. INTRODUCTION

In June 2018, the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 18-06-027, creating three new programs to promote the installation of renewable generation among residential customers in disadvantaged communities (DACs). The three programs include the DAC Single Family Solar Homes (DAC-SASH) program, which provides up-front incentives for the installation of solar at low-income homes in DACs. The other two programs, the DAC Green Tariff (DAC-GT) and the Community Solar Green Tariff (CS-GT) programs are community solar programs which offer 100% solar energy to customers and provide a 20% discount on the electric portion of the bill.

The DAC-GT program is available for residential customers who live in DACs and meet the income eligibility requirements for the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs. The CS-GT program is structured similarly to the DAC-GT program but is intended to drive more local, community-developed solar projects. The CS-GT program requires community involvement with the solar project through a local sponsor and will result in a solar facility serving a nearby community. The CS-GT program is open to all residential customers located in a DAC, with at least 50% of the program's capacity reserved for CARE and FERA eligible customers.

Both programs are funded first through greenhouse gas (GHG) allowance proceeds. If such funds are exhausted, the programs will then be funded through public purpose program (PPP) funds.

Pursuant to D.18-06-027, Community Choice Aggregators (CCAs) may develop and implement their own DAC-GT and CS-GT programs in addition to the IOU's programs. Resolution E-4999 allocated a portion of the program capacity to CCAs and determined that any CCA interested in running the programs must file an Implementation Advice Letter (AL) with the CPUC by 1/1/2021.

MCE herby submits the Implementation Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs (Implementation Plan), detailing the rules and requirements for the two programs. More specifically, the Implementation Plan contains the following sections:

- Customer eligibility and enrollment
- Rate and discount design
- Procurement
- Budget and cost recovery
- Marketing, education, and outreach
- Reporting
- Program measurement and evaluation

2. CUSTOMER ELIGIBILITY AND ENROLLMENT

This section establishes customer and sponsor eligibility and enrollment terms. These terms can also be found in the DAC-GT and CS-GT tariff schedules.

2.1. DAC-GT Program

2.1.1. Customer Eligibility

The DAC-GT program is available to residential customers who live in DACs, receive generation service from MCE, and meet the income eligibility requirements for the CARE program and/or the FERA program.[1]

DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen 3.0 tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data.[2] In the event that the CalEnviroScreen tool is updated, and MCE has unsubscribed program capacity available, MCE will file a Tier 1 Advice Letter within 30 days of the release of the new version to update program eligibility rules. Customers who are already enrolled in DAC-GT will retain their eligibility even if their census tract is no longer considered a top 25 percent DAC under the revised CalEnviroScreen.

Eligibility of customers is verified at the level of the Service Agreement ID (SA ID). Service accounts enrolled under the following programs and services are ineligible to participate in the DAC-GT program:

- IOU bundled service;
- Direct access customers;
- Standby service;
- Net energy metering (NEM) rates;
- Non-metered service;
- Rates that are not CARE- or FERA-eligible;
- Non-residential rates;

---

[1] Customers must be eligible to participate in either the CARE or FERA programs; they are not required to be enrolled under those programs to be eligible to participate in DAC-GT. CARE/FERA eligibility is established as currently defined under those programs.

[2] D.18-06-027, *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*, at p.16 and p.53.

- Master-metered customers;[3]
- Schedule CS-GT, Community Solar Green Tariff.

2.1.2. Customer Enrollment

Enrollment of customers under Schedule DAC-GT occurs at the level of the SA ID. Subscribing customers have their electricity met with 100% solar energy based on their actual usage each month and will receive a 20% discount on their otherwise applicable tariff for the enrolled SA IDs. Customer enrollment is capped at a maximum of 2 MW solar equivalent per SA ID.[4]

Customers interested in enrolling in the DAC-GT program can sign up with MCE online, by phone, or with a hardcopy application. MCE will verify customer eligibility based on service account address (to verify DAC census tract) and CARE/FERA enrollment status. If a customer is not currently enrolled in the CARE or FERA programs, they will be encouraged to enroll in the CARE/FERA programs through the existing IOU enrollment process. MCE will support the customer as needed in the CARE/FERA application process with the utility. Once a customer's CARE/FERA eligibility has been established, MCE will enroll the customer under the DAC-GT program.

Customer enrollment will be available immediately upon program launch. A participating customer can remain on the DAC-GT tariff for up to 20 years from the time of enrollment. There is no contract required when enrolling in the DAC-GT program. Customers may enroll for any number of months, and there is no enrollment or cancellation fee. Cancellation of a customer's participation will become effective on the next meter read date; cancellations made within five (5) business days of the next meter read date may not be changed for an additional billing cycle. Customers who, after enrollment into the DAC-GT Program, become ineligible for CARE or FERA will be un-enrolled from the DAC-GT program.

The customer will be placed on the DAC-GT rate on the first day of the next billing cycle where the billing cycle start date occurs at least five (5) business days after the date of the customer's request. A customer request that is received within five (5) business days of the customer's next billing cycle may result in the customer being placed on the DAC-GT rate in the following billing cycle.

Eligible customers may enroll in the program until customer subscriptions reach 4.31 MW (MCE's DAC-GT program cap). Once MCE reaches its program cap, a waitlist will be maintained for new

---

[3] MCE cannot ensure that all tenants under one master-meter are eligible for the CARE or FERA program, as the sub-metered tenants are not MCE direct customers. Hence, master-metered accounts are not eligible for the DAC-GT program.

[4] This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

subscriptions. When program capacity becomes available, MCE will enroll new eligible customers on a first-come, first-served basis up to the program cap.

A customer's service under this schedule is portable within MCE electric service area as long as the customer continues to live in a DAC as defined under the program and continues to meet all other eligibility requirements. If the customer is found to still be eligible, MCE retains their status as a program participant and does not require the customer to go on a waitlist, as long as the customer's turn-on date at the new location is within 90 days of their final billing date at their original location.

2.2. CS-GT Program

2.2.1. Customer Eligibility

The CS-GT program is available to residential customers who live in DACs (as defined above)[5] and receive generation service from MCE. Non-residential customers are not eligible to participate, except for the project sponsor (see more information on sponsor eligibility rules below). A solar generation project supporting the program must be located within five miles of the participating customers' census tract.[6] At least fifty percent of a project's capacity must be reserved for low-income customers, defined as those meeting the income qualifications for either the CARE or FERA programs.[7]

Eligibility of customers is verified at the level of the SA ID. Service accounts enrolled under the following programs and services are ineligible to participate in the CS-GT program:

- IOU bundled service;
- Direct access customers;
- Standby service;
- Net energy metering (NEM) rate;

---

[5] Customers who live in the San Joaquin Valley (SJV) pilot program communities (as defined in R.15-03-010) are also eligible for the program even if their community is not among the top 25% DACs as defined by CalEnviroScreen. Currently, there are no CCAs in existence in the SJV pilot communities. However, if the SJV pilot communities expand, an existing CCA expands or a new CCA is created, those customers would also be eligible for the CCA CS-GT program.

[6] Per D.18-12-015, *Decision Approving San Joaquin Valley Disadvantaged Communities Pilot Projects*, CS-GT projects in SJV pilot communities can be located within a 40-mile radius of the pilot communities they serve. As discussed above, there are currently no CCAs in existence in SJV pilot communities. However, if this changes, these locational requirements would also apply to CCA CS-GT programs.

[7] As under the DAC-GT program, customers do not need to be currently enrolled under CARE/FERA to be eligible for the CS-GT program. However, they will be encouraged to enroll under the CARE or FERA program through the existing IOU enrollment process when enrolling under the CS-GT program.

- Non-metered service;
- Schedule DAC-GT, Disadvantaged Communities Green Tariff.

Master-metered customers may participate in the CS-GT program so long as they enroll all of their usage under the master-metered account in the program. Individual tenants of a master-meter customer are not eligible to participate on an individual basis. Master-metered customers must also meet all other eligibility requirements.

In the event that CalEnviroScreen is updated, MCE will file a Tier 1 AL within 30 days of the release of the new version to update program eligibility rules. As with the DAC-GT program, all customers in an eligible DAC at the time of a project's initial energy delivery date will remain eligible to subscribe to that CS-GT project, even if their DAC designation changes in subsequent iterations of CalEnviroScreen. This grandfathered eligibility will apply to both existing subscribers and customers not previously subscribed to the project in that same DAC, to ensure that the project's output can be fully subscribed by customers whose census tract is within 5-miles of the project.

2.2.2. Customer Enrollment

As with DAC-GT, enrollment of customers occurs at the level of the SA ID. Customer enrollment is capped at a maximum of 2 MW solar equivalent per SA ID.[8]

The CS-GT program allows eligible customers to purchase renewable electricity produced by a local community solar project for up to 100% of their electric usage. More specifically, customers subscribe to a percentage of the solar system's project capacity based on their previous 12-month average monthly usage.[9] As described below, participating customers will receive a 20% discount on their otherwise applicable tariff for enrolled SA IDs. Customers cannot be subscribed to more than one CS facility at any time.

The following example describes the calculation of the customer's subscription allocation in more detail: We assume for this example that a residential customer has an average historical usage based on the previous 12-months of 500 kWh per month. The customer subscribes to a 100 kW community solar project with an estimated average monthly output of 21,900 kWh.[10] The customer's subscription allocation is then calculated as a percentage of the average monthly output

---

[8] This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

[9] If previous 12-month historical usage is not available, the average monthly usage will be derived from as many months as available. For customers establishing new service, the class average monthly usage will be used.

[10] Based on a capacity factor of 30%.

of the solar system (500 kWh/ 21,900 kWh = 2.3% of monthly output). In this example, the customer will subscribe to 2.3% of the project's capacity (or 2.3kW of the 100kW system). This percentage allocation is set at the time of customer subscription but may be revisited periodically to ensure accurate allocations of project capacity.

Customers interested in enrolling in the CS-GT program can sign up with MCE online, by phone, or with a hardcopy application. MCE will verify customer eligibility based on service account address to verify DAC census tract and 5-mile locational requirement. CARE/FERA enrollment status will also be identified to track subscription of low-income customers. Enrollment of new customers is available until 100% of project capacity is subscribed. Enrollment attrition will be reviewed on a monthly basis, and the program will be available for new enrollments until the project is fully subscribed.

Low-income customers will be enrolled on a first-come, first-served basis. Once 50 percent of project capacity is subscribed by low-income customers, non-low-income qualified customers located in DACs will become eligible for enrollment. These customers can be recruited before the 50 percent subscription requirement for low-income customers is met. However, they will be placed on a waitlist until 50 percent of the project capacity is subscribed by low-income customers.

MCE will assess the subscription rate of low-income customers on a monthly basis after the Power Purchase Agreement (PPA) is awarded. If the low-income subscription rate drops below 50 percent over the life of the project, existing non-low-income customers are not required to go back on a waitlist. However, new enrollments of non-low-income program participants will be barred until the 50 percent low-income threshold is met again. During this time, new enrollments of non-low-income participants will be put on a waitlist. MCE will inform the Commission's Energy Division Director in writing if the low-income enrollment rate drops below 35 percent of project capacity.

The customer will be placed on the CS-GT rate on the first day of the next billing cycle where the billing cycle start date occurs at least five (5) business days after the date of the customer's request. A customer request that is received within five (5) business days of the customer's next billing cycle may result in the customer being placed on the CS-GT rate in the following billing cycle.

Customer enrollment will be available immediately upon program launch. There is no contract required when enrolling for the CS-GT program. Customers may enroll for any number of months, and there is no enrollment or cancellation fee. Cancellation of a customer's participation will become effective on the next meter read date; cancellations made within five (5) business days of the next meter read date may not be changed for an additional billing cycle. A participating customer can remain on the CS-GT tariff for the duration of the project's contract term, or up to 20 years, whichever is less. Customer participation in the program automatically terminates should the PPA between MCE and the developer for the CS-GT facility to which the customer is subscribed be terminated or the delivery term ends.

A customer's service under this schedule is portable within MCE electric service area as long as the customer continues to live in a DAC as defined under the program and continues to meet all other eligibility requirements (including the locational requirement). If the customer is found to still be eligible, MCE will retain their status as a program participant and will not require the customer to go on a waitlist, as long as the customer's turn-on date at the new location is within 90 days of their final billing date at their original location.

2.2.3. Sponsor Eligibility

Under the CS-GT program, community involvement must be demonstrated by a non-profit community-based organization (CBO) or a local government entity "sponsoring" a community solar project on behalf of residents. Local government entities include schools. The sponsor's role is to work with the project developer to encourage program participation in the community. Sponsors are also required to include job training and workforce development in their efforts to benefit the local communities which would benefit from their projects. Additional sponsor requirements are described in the Procurement section below.

To receive the 20% discount on eligible as described below, the sponsor must fulfill the following requirements:

1. The sponsor must be an MCE electric customer;
2. The sponsor must take service on the Community Solar Green Tariff;
3. The sponsor must be located in the same geographic areas as any other customer, i.e., within a disadvantaged community with the solar project being located 5 miles from the sponsor's census tract;
4. Fifty percent of the project's capacity must be subscribed by low-income customers; and
5. The sponsor must meet all other eligibility requirements of any participating customer as described in the section on CS-GT customer eligibility above.

CBOs or local government entities that do not fulfill all or any of these requirements may still become project sponsors; however, they are not eligible to receive the 20 percent discount.

There may be more than one sponsoring entity supporting a single community solar project. Multiple sponsors may share the 20 percent discount as long as all sponsors meet the eligibility requirements outlined above.

A sponsor may also be (although is not required to be) a site host.[11]

2.2.4. Sponsor Enrollment

Sponsors of a CS-GT project are subject to the same enrollment rules and requirements as

---

[11] For the purposes of this program, the concept of a "host" only refers to a customer site where the project is located. The community solar project must be located in-front-of-the meter, even if located at a customer host site. Accordingly, all concepts and rules of an in-front-of-the-meter program continue to apply.

described above for residential customers participating in the program. For example, enrollment occurs at the level of the SA ID and is capped at a maximum of 2MW of solar equivalent per SA ID.[12]

The sponsor's subscription allocation is also calculated the same way as for any other participating customer with one modification. A sponsor's subscription allocation is limited to a maximum of 25 percent of the project's energy output (not to exceed the sponsor's energy needs).

To illustrate this in more detail, we use the same example as before (100kW solar project with a monthly output of 21,900 kWh). We assume now that the total monthly usage among all the sponsor's eligible SA IDs is 10,000 kWh, which is larger than 25% of monthly project output (5,475 kWh). In this example, the sponsor's subscription allocation is limited to 25% of project output per month, and the sponsor will receive the discount on only 5,475 kWh.

If two or more sponsors are designated, the sponsors will need to inform MCE in writing of how the "discountable usage" (in this example, 5,475 kWh/monthly) are to be allocated between them.

3. RATE AND DISCOUNT DESIGN

This section describes the rules and requirements for providing the 20 percent bill discount to participating customers.

3.1. Customer Bill Discount

Participants in both the DAC-GT and CS-GT programs will receive a 20% discount on the electric portion of the bill compared to their otherwise applicable rates (OAR).[13] The discount applies as long as customers are enrolled under the programs and they comply with all the eligibility and enrollment terms described in MCE's DAC-GT and CS-GT tariff sheets.

For low-income customers enrolled in the CARE or FERA programs, the OAR is the customer's existing CARE or FERA rate.[14] Accordingly, the 20% discount for these customers will be applied to low-income customer bills after the CARE/FERA discount has been applied.

For customers who are not enrolled in CARE or FERA programs, the OAR is the customer's

---

[12] This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

[13] D.18-06-027 at p.53 and p.74.

[14] Resolution E-4999, Conclusion 28 at p.55.

existing rate schedule before program enrollment. Residential customer SA IDs that are already enrolled in MCE's 100% renewable energy generation service option (i.e., MCE's "Deep Green" rate) when enrolling under the programs, will be defaulted to MCE's base rate (i.e., MCE's "Light Green" rate) for the purposes of calculating the 20% discount. In other words, MCE's Light Green rate becomes the de-facto OAR for residential customers who are not on the CARE or FERA rate.

A customer's electric portion of the bill consists of two main parts: (1) generation portion, and (2) delivery portion. CCAs, as the generation service provider, only have timely access to customers' generation charges, and therefore will only calculate the 20% discount for the generation portion of the electric bill. The respective utility (in MCE's case PG&E) will be responsible for calculating the 20% discount of the delivery portion of the bill for CCA program participants.

More specifically, MCE proposes the following monthly discount calculation and billing procedures for MCE program participants:

1. PG&E sends MCE customer usage information;
2. MCE calculates the 20% discount of the generation portion of the electric bill;
3. PG&E applies the CARE/ FERA discount and then calculates the 20% discount of the delivery portion of the electric bill;
4. MCE sends PG&E generation charges (reduced by 20% bill discount) for inclusion on the bill;
5. PG&E compiles the bill, sends it to customer, and gets paid by the customer;
6. PG&E pays MCE the generation charges (reduced by 20% bill discount) per established processes;
7. MCE recovers the revenue shortfall for providing the discount on the generation portion of the bill through the program's cost recovery mechanisms (see details below);
8. PG&E recovers the revenue shortfall for providing the discount on the delivery portion of the bill through the program's cost recovery mechanisms.

In regards to bill presentment, the 20% bill discount on the generation portion of the bill will be shown on the MCE portion of the bill; the 20% discount on the delivery portion of the bill is displayed on the PG&E portion of the bill.

3.2. Sponsor Bill Discount

CS-GT project sponsors who meet all of the eligibility requirements outlined above receive a 20% bill discount on enrolled SA IDs. The sponsor bill discount will be calculated based on the same methodology as described above for residential program participants with one modification. The sponsor bill discount is only applied to a sponsor's subscription allocation, i.e., limited to a maximum of 25% of the project's energy output (not to exceed the sponsor's energy needs under the enrolled SA IDs). The discount applies as long as sponsors are enrolled under the programs and they comply with all the sponsor eligibility and enrollment terms described above. If two or more sponsors are designated, both sponsors must inform MCE in writing of how the "discountable usage", capped at 25% of the project's energy output, are to be allocated among them. MCE will then calculate the applicable discount to each sponsor accordingly.

The sponsor's discount is available to sponsors only after the community solar project has reached its required minimum 50% low-income subscription rate. If the subscription rate of low-income customers drops under 50% of project capacity at any time throughout the life of the project, the sponsor bill credit will not be revoked.

4. PROCUREMENT

Per Resolution E-4999, MCE has been allocated 4.31 MW for its DAC-GT program and 1.11 MW for its CS-GT program based on the proportional share of residential customers in DACs that MCE serves.[15]

Resolution E-4999 also allows CCAs that serve customers in the same IOU service territory to share and/or trade program capacity.[16] MCE is not trading/ sharing capacity under either program at this point in time but reserves the right to do so before 1/1/2021 through a supplemental Advice Letter filing.

All renewable energy resources procured on behalf of customers participating in the DAC-GT and CS-GT programs, as well as interim resources, will comply with the California Air Resources Board's (CARB) Voluntary Renewable Electricity Program. California-eligible GHG allowances associated with these purchases will be retired on behalf of participating customers as part of CARB's Voluntary Renewable Electricity Program.

It is MCE's understanding that Green-e certification is not be feasible for the DAC-GT program under current program rules. Per D.18-06-027, 100% of a customer's annual usage is covered with solar energy under the program. Subscription to the program is based on a customer's historical usage quantities and once subscribed, no annual true-up mechanism between the sum of participating customer's total annual usage and total annual generation of all resources under the DAC-GT program will occur. It could be the case that in any given year, total customer load under the program exceeds total generation of all resources under the program. In MCE's understanding, the Green-e Energy Code of Conduct does not allow for this to happen. Hence, MCE proposes that Green-e certification is not required as a program element.

[15] Resolution E-4999, Table 1 at p.14. Due to the continued growth and expansion of CCAs, MCE recommends that the Commission review CCA capacity allocations biennially and adjust the allocation of remaining program capacity in each IOU's distribution service territory proportional to the then current share of residential customers in DACs. The first capacity allocation adjustment should occur by January 1, 2022 and every two years thereafter.

[16] Resolution E-4999 at p.54, Findings and Conclusions ¶ 17.

4.1. DAC-GT Program

DAC-GT projects must be located in a DAC within the same IOU service territory as the customers being served. DAC-GT projects located in census tracts that were previously considered a DAC under the program, but are no longer scored as such due to updates to the CalEnviroScreen tool, will continue to be eligible to serve customers under the DAC-GT program.[17]

MCE was assigned a capacity allocation of 4.31 MW for the DAC-GT program. Eligible projects must be sized between 500 kW and 20 MW (4.31 MW in MCE service area due to the program cap). MCE will consider both full deliverability and energy-only projects in the solicitations.

MCE will issue DAC-GT solicitations once a year until the program cap is reached. The solicitation process will follow these guiding principles:

1. The project is selected through a competitive solicitation;
2. MCE executes a Power Purchase Agreement (PPA) with a developer for a solar project;
3. There is no direct relationship between the customer and the project developer;
4. Subscribing customers receive 100% renewable energy; and
5. Subscribing customers receive a defined bill credit.

Eligibility for procurement under the DAC-GT program requires that bid pricing must be at or below the statewide CCA cost cap provided to CCAs by the CPUC's Energy Division Staff via email on September 5, 2019.[18]

MCE will serve DAC-GT customers on an interim basis until the new DAC-GT resources come online utilizing existing resources that meet all of the requirements of the DAC-GT program. MCE proposes to use the following solar resource under MCE's portfolio as interim resources for the DAC-GT program:[19]

- Cottonwood Solar Project (Goose Lake facility)
- Address: 15004 Corocan Rd., Lost Hills, CA 93249

---

[17] In the event that the CalEnviroScreen tool is updated, MCE will file a Tier 1 Advice Letter within 30 days of the release of the new version to update program eligibility rules.

[18] Energy Division staff explains in the email from September 5, 2019 that CCAs are expected to compare the unadjusted project bids to the price cap. In other words, CCAs should use the price cap to screen the submitted bid prices before making adjustments to those prices such as time of delivery adjustments. Energy Division staff also clarified in a workshop that the value of the CCA cost cap will change when all three IOUs procure new resources under the Green Tariff Shared Renewables (GTSR) program or under the Renewable Auction Mechanism (RAM) as-available-peaking category. Energy Division will notify the CCAs when this occurs.

[19] The solar resource is located in a DAC within PG&E's distribution service territory and is currently under contract with MCE.

- Nameplate capacity: 12 MW
- Commercial Online Date: 2015

Once the new DAC-GT solar resources come online, MCE DAC-GT customers will be transferred to these projects.

4.2. CS-GT Program

CS-GT projects must be sited in a DAC within the same IOU service territory as the customers being served and must also be located within 5 miles of the benefitting customers' DAC census tract. CS-GT projects located in census tracts that were previously considered a DAC under the program, but are no longer scored as such due to updates to the CalEnviroScreen tool, will continue to be eligible to serve customers under the CS-GT program. [20]

MCE was assigned a capacity allocation of 1.11 MW in Resolution E-4999 for the CS-GT program.[21] Eligible projects have no minimum size and a maximum size of 3 MW (1.11 MW in MCE service area due to the program cap). MCE will consider both full deliverability and energy-only projects in the solicitations.

MCE will issue CS-GT solicitations once a year until the program cap is reached. Solicitations will be run in conjunction with the DAC-GT program's solicitations. However, the DAC-GT and CS-GT program will each have separate capacity allocations and bid requirements under the same solicitation. The solicitation process will follow the same guiding principles as for the DAC-GT program:

- The project is selected through a competitive solicitation;
- MCE executes a Power Purchase Agreement ("PPA") with a developer for a solar project;
- There is no direct relationship between the customer and the project developer;
- Subscribing customers receive up to 100% renewable energy; and
- Subscribing customers receive a defined bill credit.

Eligibility for procurement under the DAC-GT program requires that bid pricing must be at or below the statewide CCA cost cap provided to CCAs by the CPUC's Energy Division Staff via email on September 5, 2019.[22]

Twenty-five percent of each project's capacity must be subscribed by eligible low-income

---

[20] In the event that the CalEnviroScreen tool is updated, MCE will file a Tier 1 Advice Letter within 30 days of the release of the new version to update program eligibility rules.

[21] Resolution E-4999, Table 2 at p.14

[22] Energy Division staff clarifies in its September 5, 2019, email that CCAs are expected to compare the unadjusted CS-GT project bids to the price cap. In other words, CCAs should use the price cap to screen the submitted bid prices before making adjustments to those prices such as time of delivery adjustments.

customers prior to permission to operate (PTO). If this requirement is not met, the project will not be able to begin delivery under the contract.[23]

Community sponsorship of the project by a CBO or local government is required to be eligible to bid for the CS-GT program. Developers will be required to obtain and provide a letter of commitment from a sponsor as part of the solicitation process. A letter of commitment from a sponsor must include:

1. Demonstration of substantial interest of community members in subscribing to the project;
2. Estimated number of subscribers, with justification to ensure project is sized to likely demand;
3. A preliminary plan to conduct outreach and recruit subscribers (which may be conducted in conjunction with the developer and/or MCE); and
4. Siting preferences, including community-suggested host sites, and verification that the site chosen for the bid is consistent with community preference.

In addition to these solicitation requirements, D.18-06-07 also established several metrics for prioritization of CS-GT project bids.[24] First, MCE will prioritize projects located in the top 5% census tracts of disadvantaged communities per CalEnviroScreen 3.0 (if applicable). Second, MCE will grant priority for projects that leverage other government funding such as a state Community Services Department (CSD) grants, or projects that provide evidence of support or endorsements from programs such as Transformative Climate Communities or other local climate initiatives. Third, MCE will also prioritize job training and workforce development factors and will require workforce development for all projects, including local hiring and targeted hiring, to enable creation of job opportunities for low-income communities.

To encourage the development of CS-GT projects, MCE will provide support to local CBOs and project developers to identify potential community solar sites within its service territory as needed. As a local government agency, MCE has existing relationships within its communities that can be leveraged to enhance the success of the CS-GT program.

5. BUDGET AND COST RECOVERY

This section describes the rules and requirements regarding program costs and budget, funding and cost recovery mechanisms, and the process of reviewing program costs.

---

[23] No interconnection or other project development processes will be influenced. The project can be finalized but payment on the delivery will not be started until 25% low-income customer subscription is achieved.

[24] D. 18-06-027 at p. 82ff

5.1. Budget

Program Administrators must submit annual program budget forecasts via a Tier 1 Advice Letter by February 1st of every year for the following program year. Each Advice Letter must include separate program budget forecasts for the DAC-GT and CS-GT programs and must clearly identify any costs that are shared between the programs.

Annual budget submissions will include, at a minimum, the following budget line items:

1. Generation cost delta, if any;[25]
2. 20 percent bill discount for participating customers;
3. Program administration costs;
4. Marketing, education and outreach (ME&O) costs; and
5. Program evaluation costs.

Generation Cost Delta

For subscribed energy, the generation cost delta is the net value of renewable resource costs and other generation-related costs used to support the program that are more or less than the resource and other generation-related costs for the typical residential rate.

MCE will calculate the generation cost delta by comparing the sum of energy contract prices, incremental Resource Adequacy (RA), and incremental shaping costs for DAC-GT and CS-GT resources with the rate for MCE's Light Green Basic Residential[26] service. The cost components are defined as follows:

- The **energy generation cost** for the DAC-GT program will be the weighted average of the energy contract prices of all solar projects under the program;
- The **energy generation cost** for the CS-GT program will be the weighted average of the specific solar project that the customer subscribes to;
- The incremental **RA value or cost** of DAC-GT and CS-GT resources are determined by CAISO Net Qualifying Capacity multiplied by 2020 RA value benchmarks, compared against the RA cost as determined by PG&E residential load profile multiplied by the 2020 RA value benchmarks;

[25] Resolution E-4999 establishes that *above market* generation costs should include net renewable resource costs in excess of the otherwise applicable class average generation rate that will be used to calculate the customers' bills. In conversations with the CPUC's Energy Division after the release of the Resolution, it was clarified that this budget line item is intended to cover both a potential higher, as well as lower, cost of the DAC-GT/ CS-GT resources than the otherwise applicable class average generation rate. Hence, the term is updated to state the "*Delta of generation costs* between the DAC-GT/ CS-GT resources and the otherwise applicable class average generation rate".

[26] Equivalent to PG&E's tiered E-1 rate. This rate currently serves approximately 90% of MCE residential accounts.

- The incremental **shaping value or cost** of DAC-GT and CS-GT resources as determined by the applicable resources' production profile multiplied by 2019 (updated annually) CAISO Day-Ahead LMP for PG&E DLAP, compared against the PG&E residential load profile multiplied by the 2019 CAISO Day-Ahead LMP for PG&E DLAP.

The delta between the base rate and the total generation cost of the DAC-GT or CS-GT resource will then be multiplied by the volume served each month by each program to arrive at the total above-market generation cost or below-market generation savings from the program.

The above/below market generation costs, if any, will not be charged to participating customers and thus will not appear on the customers' bills. Instead, the cost delta, if any, will be tracked in the background and will be charged as program costs (or credits) and recovered through GHG allowance revenue and PPP funds as outlined below.

Because new DAC-GT/ CS-GT facilities will be contracted to MCE to provide all of their output, any potential above-market costs associated with unsubscribed output will also be covered by program funds.[27] MCE will seek to sell excess energy not used by program participants to the market and any revenue received will be applied as a credit towards program funds. In preparation of the annual budget advice letter, MCE will true up the full costs for unsubscribed generation under the programs against any revenue received and will charge the remainder to the programs as a separate budget line item.

Participant Bill Discount

As described above, program participants will receive a 20-percent discount on the otherwise applicable rate of eligible SA IDs. MCE's annual program budget will include the estimated total amount of revenue loss to be experienced by providing the 20% discount on the generation portion of the bill. More specifically, this calculation will be based on forecasted monthly enrollment in each program and average monthly bills by customer class.

Program Administration and ME&O Costs

Under the DAC-GT and CS-GT programs, program administrators (PAs) can recover all program administration and ME&O costs from program funds. MCE will track program costs for the DAC-GT and CS-GT programs in separate accounts.

Administrative budget must be broken out into:

1. Program management;
2. Information technology (IT);
3. Billing operations;
4. Regulatory compliance; and

[27] D.18-06-027 at p. 83.

5. Procurement.

Marketing, education and outreach (ME&O) costs must be broken out in:

1. Labor costs;
2. Outreach and material costs;
3. Local CBO/ sponsor costs (for CS-GT only).

Resolution E-4999 establishes a budget cap of 10% of the total budget for program administration costs and a budget cap of 4% of the total budget for ME&O costs.[28] However, administrative and ME&O costs may be higher than these budget allocations in the first two years of program implementation, acknowledging that program start-up costs may be higher.

Program Evaluation Costs

The DAC-GT and CS-GT programs must be reviewed by an independent evaluator every three years. The first independent evaluator review of the utilities' DAC-GT and CS-GT programs is scheduled for January 1, 2021.

As CCA programs will launch after the utilities' programs, MCE proposes that the first evaluation of the CCAs' programs not occur before January 1, 2022. MCE will work with Energy Division to determine the appropriate scope, funding level and budget allocations for CCAs to include the program evaluation in their budgets for program year (PY) 2022 and subsequent PYs.

In addition to budget forecasts, annual program budget submissions must also include details on program capacity and customer enrollment numbers for both programs:

1. Existing capacity at previous PY close;
2. Forecasted capacity for procurement in the upcoming PY;
3. Customers served at previous PY's close; and
4. Forecasted customer enrollment for the upcoming PY.

Finally, MCE will submit the following workpapers to Energy Division staff directly:

1. Workpaper for the calculation of the generation cost delta;
2. Workpaper for the calculation of the 20% bill discount to participating customers.

Supporting worksheets used in substantiating cost estimates, including direct labor, management and/or supervisor costs, and any vendor costs, along with a breakdown of staff or contractor position descriptions, loaded hourly rates, and total hours anticipated for each task, will be provided if available.

[28] Resolution E-4999 at p.27. The Resolutions determines that Program Administrators can submit a Tier 3 Advice Letter requesting an adjustment to the budget allocations if the need arises.

Program costs will not be charged to participating customers and will thus not appear on customers' bills. Instead, the cost categories described above will be tracked and charged as program costs to the DAC-GT and CS-GT programs.

MCE submits a budget estimate for PYs 2020 and 2021 in Attachment C to the Implementation Advice Letter.

5.2. Budget Forecasting and Reconciliation Procedures

MCE will file, by February 1 of each program year, a Tier 1 Budget Advice Letter.[29] In this Annual Budget Advice Letter filing, MCE will, for each program separately:

1. Request approval of its **forecasted budget** for the upcoming program year (e.g.; by February 1, 2021 for the 2022 PY);
2. Report its **actual expenditures** during the prior program year (e.g.; by February 1, 2021 for the 2020 PY); and
3. **Reconcile** the prior year's budget forecast with actual expenditures.

5.2.1. Budget Forecast

MCE will forecast estimated program cost for the upcoming PY for all budget categories described above. For the projected revenue loss associated with providing the 20% discount to customers, MCE will estimate the total expected revenue loss for the generation portion of the electric bill. PG&E will estimate the total expected revenue loss for the delivery portion of the electric bill.

5.2.2. Report Actual Expenditures

MCE will report on actual expenditures for the previous PY for all budget categories described above. For the actual revenue loss associated with providing the 20% discount to customers, MCE will report on the actual total revenue loss for the generation portion of the electric bill. PG&E will report on the total actual revenue loss for the delivery portion of the electric bill.

The Annual Budget Advice Letter will be the mechanism for the Commission and stakeholders to review MCE actual program costs and performance. Based on the information provided in MCE's Annual Budget Advice Letter, PG&E can include a summary of actual program expenditures for the previous PY in the ERRA Compliance Review.

5.2.3. Budget Reconciliation

In the Annual Budget Advice Letter, MCE will true up forecasted program costs against actual expenditures by budget category for the prior PY. Any unspent funds from the prior PY will be used to offset the forecasted budget for the upcoming PY. If actual expenditures exceeded the

[29] The budgets for PY 2020 and 2021 are included as an attachment to this filing, hence no additional Tier 1 Advice Letter was required by February 1, 2020 for the 2021 PY.

forecast in the previous PY, MCE will add the shortfall to the forecasted budget for the upcoming PY.

5.3. Cost Recovery Procedures

Pursuant to D.18-06-027, the DAC-GT and CS-GT programs are funded first through available GHG allowance proceeds. If such funds are exhausted, the programs will be funded through public purpose program (PPP) funds. More specifically, if total forecasted annual program costs for the programs for all PAs in an IOU's service territory (i.e., IOU and CCAs) are less than the estimated GHG allowance revenues available for the programs in that IOU's service territory, all estimated program costs will be set aside from GHG allowance revenues. If total forecasted annual program costs for all PAs in an IOU service territory are greater than the GHG allowance revenues available for the programs, all available GHG allowance revenues will be set aside for the programs, and the shortfall in funds will be allocated to PPP funds.

D.18-06-027 authorizes CCAs to access GHG allowance revenues and/or PPP funds to run the DAC-GT and CS-GT programs.[30] The IOUs administer the GHG allowance revenues and collect PPP funds, and have established balancing accounts for the DAC-GT and CS-GT programs. CCAs are not in the position to either access those funds directly or establish balancing accounts to track program costs. Therefore, MCE requests that the Commission direct PG&E to modify its DAC-GT and CS-GT balancing accounts to include a sub-account to track the funding and costs of MCE's DAC-GT and CS-GT programs. Additionally, PG&E will be responsible for determining and tracking whether and how much of the funding for MCE's DAC-GT and CS-GT programs comes from GHG-allowance revenues versus PPP funds.

Once the Commission approves MCE's Annual Budget Advice Letter, PG&E will include the total budget estimate for the upcoming PY for MCE's DAC-GT and CS-GT programs in the ERRA Forecast filing due in early June of each year. Once PG&E receives approval of its ERRA Forecast from the Commission, PG&E will set aside the requested MCE budget in a sub-account of its DAC-GT and CS-GT balancing accounts. PG&E will then transfer program funds to MCE in four quarterly installments (by January 1, April 1, July 1 and October 1 of each year) for the upcoming quarter.[31]

If the ERRA Forecast is not approved by January 1 of a given PY, PG&E will transfer all past due funds to MCE within thirty days of issuance of such approval.

[30] D.18-06-027, Ordering Paragraph 17, at p. 104.

[31] In 2020, depending on the timing of the Commission's approval of this Advice Letter, PG&E will include both the PY 2020 and PY 2021 budget estimates in its 2021 ERRA Forecast filing in early June or in its 2021 ERRA November update. Once the 2021 ERRA Forecast is approved, PG&E will transfer all past due PY 2020 funds within thirty days of issuance of such approval.

6. MARKETING, EDUCATION AND OUTREACH

MCE will establish a ME&O program to promote customer participation in the DAC-GT and CS-GT programs. MCE plans to directly implement the ME&O program and execute outreach.

MCE is submitting a ME&O plan for PYs 2020-2021 in Attachment D to the Implementation Advice Letter.[32] The ME&O plan discusses specific methods for customer outreach, including any coordination with local CBO sponsors and associated funding. The plan addresses how MCE will work to identify residential customers in DACs who are likely eligible for the CARE and FERA programs, but who are not yet enrolled. Finally, the plan discusses how to leverage existing customer programs to market the DAC-GT and CS-GT programs.

MCE will file annual ME&O plans and detailed budgets by February 1 of each year for the upcoming PY, starting in 2021.

7. REPORTING

Within 30 calendar days after the end of each calendar quarter, MCE will file a quarterly report for both programs, distinguishing between the DAC-GT and CS-GT program data. The quarterly report will detail:

- Procured capacity;
- Online capacity;
- DACs in which projects are located;
- Number of participating customers in each DAC within MCE's service territory;
- Number of customers who have successfully enrolled in CARE and FERA in the process of signing up for the DAC-GT or CS-GT programs.

The quarterly report will be filed in R.14-07-002 and served onto the same service list.

Semi-annually, within 30 calendar days after the end of each six-month period of the year, MCE will report the following information for CS-GT projects to the Commission's Energy Division Central Files:

- Number of income-qualified customers subscribed to each project and the capacity those customers are receiving;
- Whether a waitlist of non-income-qualified customers exist and the size of that list;
- If project sponsors are receiving bill credits under CS-GT projects and the size of each sponsor's subscription; and

[32] The ME&O plan and budget for PY 2020 are subject to change depending on the date of approval of the Implementation Advice Letter.

- The number of master-metered properties served on the CS-GT tariff and the total capacity those properties are subscribed to receive.

MCE's first quarterly or semi-annual report will be filed on the first scheduled due date after customer enrollment begins.

8. PROGRAM MEASUREMENT AND EVALUATION

An independent evaluator will review the utilities' DAC-GT and the CS-GT programs every three years beginning in 2021.[33] The CS-GT program must also be assessed by the same independent evaluator one year after program launch.[34]

MCE proposes commencing independent evaluation for CCA DAC-GT and CS-GT programs at the beginning of the upcoming PY after customers have been enrolled under the program for a minimum of one full year (e.g. if the DAC-GT program were to launch with interim resources by the fall of 2020, the first program evaluation would occur on January 1, 2022). MCE will work with Energy Division to determine the appropriate scope, funding level and budget allocations for CCAs to include the program evaluation in their program budgets for PY 2022 and subsequent PYs.

[33] The CPUC's Energy Division will select the independent evaluator through a Request for Proposal (RFP) process managed by San Diego Gas & Electric Company on behalf of the Commission. The RFP process will be led by staff from the Commission's Energy Division, and Energy Division staff will make the final decision on the winning bidder.

[34] Resolution E-4999 clarified that it is appropriate to interpret the first year of the CS-GT program as the first-year customers are able to subscribe to projects. Thus, if no customers have subscribed to CS-GT projects by 2021, the initial independent evaluator review in 2021 will replace the evaluation of the CS-GT program after the first year.

APPENDIX B

ELECTRIC SCHEDULE CS-GT

COMMUNITY SOLAR GREEN TARIFF PROGRAM

Effective Date: [TBD upon Commission approval]

APPLICABILITY

The Community Solar Green Tariff (CS-GT) is a voluntary rate supplement to the customer's otherwise applicable rate schedule (OAS) under which eligible customers have their electricity usage met with up to 100% solar energy produced by a local community solar project while also receiving a 20% discount on their OAS.

1. Residential Customer Eligibility

To enroll under the rate, a customer must meet the following eligibility requirements:

- Customers must receive electric generation service from MCE;
- Customer must be on a residential rate, except for the project sponsor;
- At least fifty percent of a project's capacity must be reserved by low-income customers, defined as those meeting the income qualifications for either the California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance (FERA) programs;
- The customer's service address must be located in a disadvantaged community (DAC). DACs are defined as communities that are identified in the CalEnviroScreen 3.0 tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data. In the event that the CalEnviroScreen tool is updated, enrolled customers will retain their eligibility even if their census tract is no longer considered an eligible DAC as defined above. This grandfathered eligibility will apply to both existing subscribers and customers not previously subscribed to the project in that same DAC, to ensure that the project's output can be fully subscribed by customers whose census tract is within 5-miles of the project.

- The solar generation project customers subscribe to must be located within five miles of the participating customers' census tract.

Service accounts enrolled under the following programs and services are ineligible to enroll under the CS-GT rate:

- Standby service
- Net energy metering (NEM) rates;
- Non-metered service;
- Customers enrolled in Disadvantaged Communities Green Tariff (DAC-GT) rate schedule.

Master-metered customers may participate in the CS-GT program so long as they enroll all of their usage under the master-metered account in the program. Individual tenants of a master-meter customer are not eligible to participate on an individual basis. Master-metered customers must also meet all other eligibility requirements.

Eligibility of customers is verified at the level of the Service Agreement ID (SA ID).

2. Sponsor Eligibility

Under the CS-GT rate, community involvement must be demonstrated by a non-profit community-based organization (CBO), a local government entity, or a school "sponsoring" a community solar project on behalf of residents. The sponsor's role is to work with the project developer to encourage program participation in the community.

To receive the 20% discount on eligible SA IDs as described below, the sponsor must fulfill the following requirements:

1. The sponsor must be an MCE electric customer;
2. The sponsor must take service on the Community Solar Green Tariff;
3. The sponsor must be located in the same geographic areas as any other customer, i.e., within a disadvantaged community with the solar project being located 5 miles from the sponsor's census tract;
4. Fifty percent of the project's capacity must be subscribed by low-income customers; and
5. The sponsor must meet all other eligibility requirements of any participating customer as described in the section on CS-GT customer eligibility above (including ineligible rate schedules).

Sponsors that do not fulfill all or any of these requirements may still become project sponsors; however, they are not eligible to receive the 20 percent discount.

There may be more than one sponsoring entity supporting a single community solar project. Multiple sponsors may share the 20% discount as long as all sponsors meet the eligibility requirements outlined above.

A sponsor may also be (although is not required to be) a site host.[1]

ENROLLMENT TERMS

1. Residential Customer Enrollment

Enrollment of customers under Schedule CS-GT occurs at the level of the SA ID. Customer enrollment is capped at a maximum of 2 MW solar equivalent per SA ID. This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

Customers subscribe to a percentage of the solar system's project capacity based on their previous 12-month average monthly usage.[2] This percentage allocation is set at the time of customer subscription but may be revisited periodically to ensure accurate allocations of project capacity. Customers cannot be subscribed to more than one CS facility at any time.

Eligible customers may enroll under the rate on a first-come, first-served basis until customer subscriptions reach MCE's CS-GT program cap. Once MCE reaches its program cap, a wait list will be maintained for new subscriptions. When program capacity becomes available, MCE will continue enrolling eligible customers either from the waitlist (if applicable), or on a first-come, first-served basis up to the program cap.

Low-income customers will be enrolled on a first-come, first-served basis. Once 50 percent of project capacity is subscribed by low-income customers, non-low-income qualified customers located in DACs will become eligible for enrollment. These customers can be recruited before the 50 percent subscription requirement for low-income customers is met. However, they will be placed on a waitlist until 50 percent of the project capacity is subscribed by low-income customers. If the low-income subscription rate drops below 50 percent over the life of the project, existing non-low-income customers are not required to go back on a waitlist. However, new enrollments of non-low-income program participants will be barred until the 50 percent low-income threshold is met again. During this time, new enrollments of non-low-income participants will be put on a waitlist.

The customer will be placed on the CS-GT rate on the first day of the next billing cycle where the billing cycle start date occurs at least five (5) business days after the date of the customer's request. A customer request that is received within five (5) business days of the customer's next billing cycle may result in the customer being placed on the CS-GT rate in the following billing cycle.

---

[1] For the purposes of this program, the concept of a "host" only refers to a customer site where the project is located. The community solar project must be located in-front-of-the meter, even if located at a customer host site. Accordingly, all concepts and rules of an in-front-of-the-meter program continue to apply.

[2] If previous 12-month historical usage is not available, the average monthly usage will be derived from as many months as available. For customers establishing new service, the class average monthly usage will be used.

A participating customer can remain on the CS-GT rate for the duration of the solar project's contract term, or up to 20 years, whichever is less. There is no contract required when enrolling in the DAC-GT program. Customers may enroll for any number of months, and there is no enrollment or cancellation fee. Cancellation of a customer's participation will become effective on the next meter read date; cancellations made within five (5) business days of the next meter read date may not be changed for an additional billing cycle. Customer participation in the program automatically terminates should the PPA between MCE and the developer for the CS-GT facility to which the customer is subscribed be terminated or the delivery term ends.

A customer's service under this schedule is portable within MCE electric service area as long as the customer continues to live in a DAC as defined under the program and continues to meet all other eligibility requirements. If the customer is found to still be eligible, MCE retains their status as a program participant and does not require the customer to go on a waitlist, as long as the customer's turn-on date at the new location is within 90 days of their final billing date at their original location.

2. **Sponsor Enrollment**

Sponsors of a CS-GT project are subject to the same enrollment rules and requirements as described above for residential customers with one modification. A sponsor's subscription allocation is limited to a maximum of 25 percent of the project's energy output (not to exceed the sponsor's energy needs).

The same principle applies if multiple sponsors share the 20% discount. If two or more sponsors are designated, the sponsors will need to inform MCE in writing of how the "discountable usage" are to be allocated between them.

RATES

1. **Residential Customer Rates**

Customers taking service on this rate schedule will receive a twenty (20) percent discount on the electric portion of the bill compared to their OAS. The discount applies as long as customers are enrolled under the programs and they comply with all the eligibility and enrollment terms.

For low-income customers enrolled in the CARE or FERA programs, the OAS is the customer's existing CARE or FERA rate. Accordingly, the 20% discount for these customers will be applied to low-income customer bills after the CARE/FERA discount has been applied.

For customers who are not enrolled in CARE or FERA programs, the OAS is the customer's existing rate schedule before program enrollment. Residential customer SA IDs that are already enrolled in MCE's 100% renewable energy generation service option (i.e., MCE's "Deep Green" rate) when enrolling under the programs, will be defaulted to MCE's base rate (i.e., MCE's "Light Green" rate) for the purposes of calculating the 20 percent discount.

2. **Sponsor Rates**

CS-GT project sponsors who meet all of the eligibility requirements outlined above receive a twenty (20) percent bill discount on enrolled SA IDs. The sponsor bill discount will be calculated based on the same methodology as described above for residential program participants with one modification. The sponsor bill discount is only applied to a sponsor's subscription allocation, i.e. limited to a maximum of 25% of the project's energy output (not to exceed the sponsor's energy needs under the enrolled SA IDs). The discount applies as long as sponsors are enrolled under the programs and they comply with all the sponsor eligibility and enrollment terms described above.

If two or more sponsors are designated, both sponsors must inform MCE in writing of how the "discountable usage", capped at 25% of the project's energy output, are to be allocated among them. MCE will then calculate the applicable discount to each sponsor accordingly.

The sponsor's discount is available to sponsors only after the community solar project has reached its required minimum 50% low-income subscription rate. If the subscription rate of low-income customers drops under 50% of project capacity at any time throughout the life of the project, the sponsor bill credit will not be revoked.

BILLING

Monthly bills are calculated in accordance with the customer's OAS and the provisions contained herein. The amount credited under Schedule CS-GT is provided by both PG&E and MCE: MCE calculates the twenty (20) percent discount for the generation portion of the electric bill and PG&E calculates the twenty (20) percent discount for the delivery portion of the electric bill.

Both entities display the discount on their respective portion of the customer's utility bill.

METERING

All customers must be metered according to the requirements of their OAS.

ELECTRIC SCHEDULE DAC-GT

DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM

Effective Date: [TBD upon Commission approval]

APPLICABILITY

The Disadvantaged Communities Green Tariff (DAC-GT) is a voluntary rate supplement to the customer's otherwise applicable rate schedule (OAS) under which eligible customers have their electricity usage met with 100% solar energy based on their actual usage each month while also receiving a 20% discount on their OAS.

To enroll under the rate, a customer must meet the following eligibility requirements:

- Customers must receive electric generation service from MCE;
- Customer must be on a residential rate;
- Customer must meet the income eligibility requirements for the California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance (FERA) programs;
- The customer's service address must be located in a disadvantaged community (DAC). DACs are defined as communities that are identified in the CalEnviroScreen 3.0 tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data. In the event that the CalEnviroScreen tool is updated, enrolled customers will retain their eligibility even if their census tract is no longer considered an eligible DAC as defined above.

Service accounts enrolled under the following programs and services are ineligible to enroll under the DAC-GT rate:

- Standby service
- Net energy metering (NEM) rates;
- Non-metered service;
- Rates that are not CARE- or FERA-eligible;
- Non-residential rates;

- Master-metered customers;
- Customers enrolled in Community Solar Green Tariff (CS-GT) rate schedule.

Eligibility of customers is verified at the level of the Service Agreement ID (SA ID).

ENROLLMENT TERMS

Enrollment of customers under Schedule DAC-GT occurs at the level of the SA ID. Customer enrollment is capped at a maximum of 2 MW solar equivalent per SA ID. This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

Eligible customers may enroll under the rate on a first-come, first-served basis until customer subscriptions reach MCE's DAC-GT program cap. Once MCE reaches its program cap, a wait list will be maintained for new subscriptions. When program capacity becomes available, MCE will continue enrolling eligible customers either from the waitlist (if applicable), or on a first-come, first-served basis up to the program cap.

The customer will be placed on the DAC-GT rate on the first day of the next billing cycle where the billing cycle start date occurs at least five (5) business days after the date of the customer's request. A customer request that is received within five (5) business days of the customer's next billing cycle may result in the customer being placed on the DAC-GT rate in the following billing cycle.

A participating customer can remain on the DAC-GT tariff for up to 20 years from the time of enrollment. There is no contract required when enrolling in the DAC-GT program. Customers may enroll for any number of months, and there is no enrollment or cancellation fee. Cancellation of a customer's participation will become effective on the next meter read date; cancellations made within five (5) business days of the next meter read date may not be changed for an additional billing cycle.

A customer's service under this schedule is portable within MCE electric service area as long as the customer continues to live in a DAC as defined under the program and continues to meet all other eligibility requirements. If the customer is found to still be eligible, MCE retains their status as a program participant and does not require the customer to go on a waitlist, as long as the customer's turn-on date at the new location is within 90 days of their final billing date at their original location.

Customers who, after enrollment into the DAC-GT Program, become ineligible for CARE or FERA will be de-enrolled from the DAC-GT program.

RATES

Customers taking service on this rate schedule will receive a twenty (20) percent discount on the electric portion of the bill compared to their OAS. The discount applies as long as customers are enrolled under the programs and they comply with all the eligibility and enrollment terms.

For low-income customers enrolled in the CARE or FERA programs, the OAS is the customer's existing CARE or FERA rate. Accordingly, the 20% discount for these customers will be applied to low-income customer bills after the CARE/FERA discount has been applied.

For customers who are not enrolled in CARE or FERA programs, the OAR is the customer's existing rate schedule before program enrollment. Residential customer SA IDs that are already enrolled in MCE's 100% renewable energy generation service option (i.e., MCE's "Deep Green" rate) when enrolling under the programs, will be defaulted to MCE's base rate (i.e., MCE's "Light Green" rate) for the purposes of calculating the 20 percent discount.

BILLING

Monthly bills are calculated in accordance with the customer's OAS and the provisions contained herein. The amount credited under Schedule DAC-GT is provided by both PG&E and MCE: MCE calculates the twenty (20) percent discount for the generation portion of the electric bill and PG&E calculates the twenty (20) percent discount for the delivery portion of the electric bill.

Both entities display the discount on their respective portion of the customer's utility bill.

METERING

All customers must be metered according to the requirements of their OAS.

APPENDIX C

Budget Forecast for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs for the Program Years 2020 and 2021

Proposed by Marin Clean Energy

Alice Havenar-Daughton
Director of Customer Programs
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
E-mail: ahavenar-daughton@mcecleanenergy.org

May 7, 2020

Table of Contents

Table of Figures

1. PURPOSE

Pursuant to Ordering Paragraph (OP) 17 of Decision (D.)18-06-027 *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities* and guidance provided in Resolution E-4999, MCE hereby submits this budget forecast for the Disadvantaged Communities Green Tariff (DAC-GT) and the Community Solar Green Tariff (CS-GT) programs for Program Years (PY) 2020 and 2021.[1]

MCE requests that the budgets proposed herein be approved by the Commission and that the Commission direct PG&E to transfer funds sufficient to meet MCE's approved annual budgets per the funding mechanisms discussed below.

2. BACKGROUND

Per Resolution E-4999, estimated budget forecasts must be presented by program and include the following budget line items:[2]

1. Generation cost delta, if any;[3]
2. 20 percent bill discount for participating customers (generation portion);
3. Program administration costs:
    a. Program management;
    b. Information technology (IT);
    c. Billing operations;
    d. Regulatory compliance; and
    e. Procurement.
4. Marketing, education and outreach (ME&O) costs:
    a. Labor costs;
    b. Outreach and material costs;
    c. Local CBO/ sponsor costs (for CS-GT only);
5. Program evaluation costs.

In addition to budget forecasts, annual program budget submissions also include details on program capacity and customer enrollment numbers for both programs. More specifically, MCE reports on

1. Existing capacity at previous PY's close;

[1] In future program years, this annual program budget will also include actual program costs from the previous PY, as well as a reconciliation of forecasted versus actual costs.

[2] A detailed description of each budget line item can be found in MCE's Implementation Plan, submitted in Appendix A to the Implementation Advice Letter.

[3] Resolution E-4999 establishes that *above market* generation costs should include net renewable resource costs in excess of the otherwise applicable class average generation rate that will be used to calculate the customers' bills. In conversations with the CPUC's Energy Division after the release of the Resolution, it was clarified that this budget line item is intended to cover both a potential higher, as well as lower, cost of the DAC-GT/ CS-GT resources than the otherwise applicable class average generation rate. Hence, the term is updated to state the "*Delta of generation costs* between the DAC-GT/ CS-GT resources and the otherwise applicable class average generation rate".

2. Forecasted capacity for procurement in the upcoming PY;
3. Customers served at previous PY's close; and
4. Forecasted customer enrollment for the upcoming PY.

Finally, MCE will submit the following workpapers to the California Public Utilities Commission (CPUC or Commission) Energy Division staff directly:

1. Workpaper for the calculation of the generation cost delta;
2. Workpaper for the calculation of the 20% bill discount to participating customers.

Supporting worksheets used in substantiating cost estimates, including direct labor, management and/or supervisor costs, and any vendor costs, along with a breakdown of staff or contractor position descriptions, loaded hourly rates, and total hours anticipated for each task, will be provided if requested and available.

3. BUDGET FORECAST FOR PY 2020 AND 2021

For PYs 2020-2021, MCE requests a total budget of $ $1,992,897 for the DAC-GT and CS-GT programs. A detailed budget forecast for each program and PY by budget line item can be found in the table below.

Table 1: MCE Budget Forecast for PYs 2020 and 2021

Tab	Category	DAC-GT			CS-GT			
		2020	**2021**	**Total**	**2020**	**2021**	**Total**	
1	Generation Cost Delta	$ 36,199	$ 796,342	**$ 832,541**	$ -	$ -	**$ -**	
2	20% Bill Discount	$ 7,564	$ 162,571	**$ 170,135**	$ -	$ -	**$ -**	
	Program Administration							
3a	Program Management	$ 118,820	$ 93,000	**$ 211,820**	$ 89,420	$ 125,400	**$ 214,820**	
3b	Information Technology	$ 24,814	$ 5,940	**$ 30,754**	$ 24,814	$ 9,090	**$ 33,904**	
3c	Billing Operations	$ 23,180	$ 34,830	**$ 58,010**	$ 5,970	$ 8,970	**$ 14,940**	
3d	Regulatory Compliance	$ 11,760	$ 6,480	**$ 18,240**	$ 11,760	$ 6,480	**$ 18,240**	
3e	Procurement	$ 20,295	$ 16,045	**$ 36,340**	$ 34,995	$ 21,445	**$ 56,440**	
	Subtotal Program Administration	**$ 198,869**	**$ 156,295**	**$ 355,164**	**$ 166,959**	**$ 171,385**	**$ 338,344**	
	Marketing, Education & Outreach							
41	Labor Costs	$ 47,040	$ 63,720	**$ 110,760**	$ 5,390	$ 14,364	**$ 19,754**	
4b	Outreach and Material Costs	$ 72,400	$ 34,250	**$ 106,650**	$ 3,000	$ 21,550	**$ 24,550**	
4c	Local CBO/ Sponsor Costs	$ -	$ -	**$ -**	$ 15,000	$ 20,000	**$ 35,000**	
	Subtotal ME&O	**$ 119,440**	**$ 97,970**	**$ 217,410**	**$ 23,390**	**$ 55,914**	**$ 79,304**	
5	EM&V	$ -	$ -	**$ -**	$ -	$ -	**$ -**	
Total		**$ 362,071**	**$ 1,213,178**	**$ 1,575,249**	**$ 190,349**	**$ 227,299**	**$ 417,648**	**$ 1,992,897**

MCE provides the following clarifying notes regarding the budget summary.

Generation Cost Delta
MCE does not anticipate having *new* DAC-GT or CS-GT projects come online in 2020 or 2021 due to the need for soliciting such projects. However, for the DAC-GT program, MCE will use an interim project while new projects are being solicited and built. Hence, the generation cost delta budget forecast for the DAC-GT program is based on the cost of the interim resource selected. More detail is provided in the Implementation Plan in Appendix A to the Implementation Advice Letter.

20 Percent Bill Discount
As described in more detail in MCE's Implementation Plan, MCE proposes to only calculate the 20% discount for the generation portion of the electric bill. The respective utility (in MCE's case PG&E) will be responsible for calculating the 20% discount on the delivery portion of the bill for CCA program participants. Hence, the budget forecasted for providing the bill discount to customers for the DAC-GT program is based on the revenue loss experienced by providing a 20% discount on the <u>generation portion</u> of the electric bill, not the full electric bill.
As mentioned above, MCE does not expect to enroll customers in the CS-GT program in PYs 2020 or 2021 as new solar resources must be procured for this program.

Program Administration Costs
Program management includes program development and management, budgeting, and reporting. IT costs include the costs to develop program tools and updating existing systems to accommodate program enrollment and billing. Billing operations covers costs for ongoing billing operations and customer support once all systems are developed. Regulatory covers costs for regulatory compliance and related program filings with the Commission. Procurement covers the costs to develop and manage the solicitations for solar resources under the program, as well as annual renewable energy credit (REC) retirement and compliance functions.

Marketing, Education and Outreach (ME&O)
ME&O budgets are split in three categories – (1) MCE labor costs; (2) MCE direct costs for outreach and material; and (3) funds provided to the local CBOs who function as the sponsor for the CS-GT program.

Evaluation, Measurement and Verification (EM&V)
MCE proposes commencing independent evaluation for CCA DAC-GT and CS-GT programs at the beginning of the upcoming PY after customers have been enrolled under the program for a minimum of one full year (e.g., if the DAC-GT program were to launch with interim resources by the fall of 2020, the first program evaluation would occur on January 1, 2022). Hence, MCE does not include any budget forecast for EM&V in the budget for PYs 2020 and 2021.

4. BUDGET CAPS

Resolution E-4999 establishes a budget cap of 10% of the total budget for program administration costs and a budget cap of 4% of the total budget for ME&O costs.[4] However, administrative and ME&O costs may be higher than these budget allocations in the first two years of program implementation (i.e., PYs 2020 and 2021 for MCE), acknowledging that program start-up costs may be higher. Hence, MCE will only include information on budget caps in subsequent submissions of the Annual Budget Advice Letter.

5. PROGRAM CAPACITY AND ENROLLMENT NUMBERS

MCE reports forecasted program capacity and customer enrollment numbers for PYs 2020 and 2021 in the table below. MCE is unable to report on existing program capacity and customer enrollment numbers to date as the programs have not launched yet.

MCE is only reporting estimated program capacity and enrollment numbers for the DAC-GT program, as this program is expected to be served by an interim solar resource in MCE's portfolio while new resources are being procured specifically for the program. For the CS-GT program, MCE will procure new solar resources that are only expected to come online in 2022.

Table 2: Program Capacity and Enrollment Count for DAC-GT

Category	DAC-GT		
	2020	2021	Total
Estimated capacity to be procured (MW)	4.31	0	**4.31**
Estimated customer enrollment (#)	450	1686	**2136**

6. COST RECOVERY AND FUND TRANSFER PROCEDURES

Once the Commission approves MCE's budget request, PG&E will be responsible for including the total budget request for MCE's DAC-GT and CS-GT programs in the ERRA Forecast filing due in early June of each year (or in the ERRA Update in early November, as available). Once PG&E receives approval of its ERRA Forecast from the Commission, PG&E will set aside the requested MCE budget in a sub-account of its DAC-GT and CS-GT balancing accounts. PG&E will then transfer program funds to MCE in four quarterly installments (by January 1, April 1, July 1 and October 1 of each year) for the upcoming quarter.
For 2020 program funds, PG&E must transfer all past due funds within thirty days of approval of the 2021 ERRA Forecast filing.

7. CONCLUSION

MCE respectfully requests the Commission approve the budgets proposed herein and direct PG&E to transfer funds sufficient to meet MCE's approved annual budgets per the funding mechanisms

[4] Resolution E-4999 determined that Program Administrators can submit a Tier 3 Advice Letter requesting an adjustment to the budget allocations if the need arises. See Resolution E-4999 at p.27.

discussed above.

APPENDIX D

Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs for Program Years 2020 and 2021

Proposed by Marin Clean Energy

Alice Havenar-Daughton
Director of Customer Programs
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
E-mail: ahavenar-daughton@mcecleanenergy.org

May 7, 2020

TABLE OF CONTENTS

TABLE OF FIGURES

1. PURPOSE AND GOALS

MCE will develop and implement a targeted customer marketing, education, and outreach (ME&O) campaign under the Disadvantaged Communities Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs to ensure potential customers in disadvantaged communities (DACs) are aware of the opportunity to benefit from the programs. MCE's ME&O strategy has four main goals:

1. Enroll eligible customers in the DAC-GT and CS-GT programs;
2. Increase awareness of, and enrollment in, California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs;
3. Increase customer awareness of energy use, savings opportunities, other customer incentives, rate options (i.e. TOU), discounts, or programs;
4. Address barriers to program participation and leverage best practices to participation and ensure that outreach to DAC and hard-to-reach customers is accessible and equitable.

Throughout this process, MCE aims to achieve meaningful and diverse customer engagement through a culturally-competent, multilingual approach. To achieve these goals, MCE will develop a targeted customer engagement campaign that leverages community-based marketing best practices such as:

- A mix of multilingual and culturally-competent communications including community advertising (e.g., banners, newsprint), geo-targeted digital ads, and direct mail, and
- Direct customer outreach and partnerships with community-based organizations (CBOs) and local government agencies.

Ultimately, MCE will measure ME&O program success by the number of customers enrolled in the DAC-GT and CS-GT programs. We will also measure program success by the overall number of customers reached, and the diversity of customers reached.

The following subsections provide additional details about MCE's ME&O approach for the DAC-GT and CS-GT programs.

2. GUIDING PRINCIPLES

MCE is committed to developing diverse and culturally appropriate communication strategies to ensure that stakeholders can participate in decisions and actions that impact their communities. As such, MCE commits to the following guiding principles throughout the ME&O engagement process for the DAC-GT and CS-GT programs. MCE aims to:

- Achieve diverse and meaningful engagement that reflects the demographics of DAC communities to ensure equitable outreach across race, income and age barriers;
- Maintain transparency and accessibility of information by bringing the information directly to customers in their neighborhood, their community, or interest space to better engage them in the process;
- Build a collaborative process with community partners to ensure barriers and benefits to participation are considered in the ME&O activities to the maximum extent possible.

3. TARGET AUDIENCE

Given enrollment specifications around the programs, the primary target audience for the ME&O strategy are existing and eligible CARE/FERA customers living in DAC communities per CalEnviroscreen. In MCE's service area, DAC communities include customers in the following neighborhoods:

Figure 1. Qualifying Neighborhoods in MCE Service Territory

Census Tract	Nearby City (to help approximate location only)	ZIP	California County
6013305000	Antioch	94509	Contra Costa
6013320001	Martinez	94553	Contra Costa
6013302005	Oakley	94561	Contra Costa
6013312000	Pittsburg	94565	Contra Costa
6013310000	Pittsburg	94565	Contra Costa
6013311000	Pittsburg	94565	Contra Costa
6013314103	Pittsburg	94565	Contra Costa
6013314104	Pittsburg	94565	Contra Costa
6013313102	Pittsburg	94565	Contra Costa
6013309000	Pittsburg	94565	Contra Costa
6013313101	Pittsburg	94565	Contra Costa
6013379000	Richmond	94804	Contra Costa
6013365002	Richmond	94801	Contra Costa
6013377000	Richmond	94801	Contra Costa
6013382000	Richmond	94804	Contra Costa
6013376000	Richmond	94801	Contra Costa
6013380000	Richmond	94804	Contra Costa
6013375000	Richmond	94801	Contra Costa
6013381000	Richmond	94804	Contra Costa
6013358000	Rodeo	94572	Contra Costa
6013368002	San Pablo	94806	Contra Costa
6013366002	San Pablo	94806	Contra Costa
6013368001	San Pablo	94806	Contra Costa
6013364002	San Pablo	94806	Contra Costa
6013392200	San Pablo	94806	Contra Costa
6095250701	Vallejo	94590	Solano
6095250801	Vallejo	94592	Solano
6095250900	Vallejo	94590	Solano
6095251802	Vallejo	94589	Solano
6095251901	Vallejo	94589	Solano

4. ME&O TACTICS AND STRATEGIES

4.1. Communications and Media Content

A variety of communications and media content will be developed to promote the programs, including flyers and fact sheets, as well as content on MCE's website. This material will be translated and improved throughout the ME&O strategy via message testing to ensure it is culturally competent and effective. Additionally, MCE will run social media campaigns, as well as print and digital advertisements, in multiple languages to encourage program enrollment. Direct mailing and email blasts will also be utilized to target customers.

4.2. Community Outreach

To meet our ME&O goals, MCE will develop an outreach and engagement strategy leveraging the key community outreach tactics summarized below. The community outreach strategy will include a multilingual and culturally competent approach to engagement and consider the specific needs of DAC communities in MCE's service area. Outreach will be informed by data (census tracks, 4013, etc.) in order to identify customers who are most likely to enroll in the programs.

4.2.1. Grassroots Outreach

MCE will conduct grassroots outreach to engage directly with community members at community events. MCE already regularly attends and sponsors many community events throughout its service area, including neighborhood festivals, farmers markets, holiday celebrations, and special events. Under the community outreach strategy for the DAC-GT and CS-GT programs, MCE will focus on expanding the breadth of events attended in DAC neighborhoods.

MCE will utilize the expertise of community leaders to identify impactful events and will offer workshops and webinars as appropriate. As community events and workshops are held, we will closely track the diversity in race, age and income of participants, to ensure that participation reflects census distribution demographics of the DAC communities. Additionally, we will maximize convenience of meetings and events to public transportation, and ensure events are ADA accessible.

4.2.2. Partnerships with Community Based Organizations

Partnering with Community Based Organizations (CBOs) is a critical facet of MCE's ME&O plan. CBOs have intimate knowledge of the local communities they serve and will serve as valuable resources for how best to conduct outreach that makes sense for members of their communities. As MCE engages with CBO partners, we seek to establish open dialogue, build awareness and understanding among community members, identify community-specific issues, and develop methods for disseminating relevant information. For example, CBOs will help coordinate program-specific workshops to disseminate program information to their constituencies. MCE will provide funding for CBOs to conduct outreach around the DAC-GT and CS-GT programs.

Additionally, many other local City departments already conduct outreach in the same communities in which we will conduct program outreach. MCE will investigate and pursue opportunities to collaborate as appropriate.

4.3. Program Leveraging

California offers a plethora of clean energy, energy efficiency, and energy storage programs, with several of them targeting income-qualified customers or customers in DACs. Complementing the state's programs, MCE also has developed a wide range of in-house program offerings with many of them focusing on vulnerable customers. MCE's Single Point of Contact (SPOC) model provides "behind-the-scene" coordination with various programs and funding sources in order to provide MCE's customers with the comprehensive, streamlined "one-stop-shop" guidance they need to navigate and enroll in these different offerings, maximizing the benefit to the customers while interweaving the value of all leveraged programs.

Under the DAC-GT/CS-GT ME&O plan, MCE will leverage its relationships and interactions with customers through existing programs to inform, educate and encourage program participation through its SPOC model. For example, MCE will leverage the following programs for joint outreach efforts: MCE's newly developed Battery Energy Storage Programs, MCE's low-income solar program for homeowners, MCE's Low-Income Families and Tenants (LIFT) pilot that offers energy efficiency upgrades to low-income multifamily properties, and the MCEv program, an electric vehicle rebate program for low-income customers.

Additionally, MCE will pursue program leveraging with relevant programs run by partners and other local CBOs and government entities.

Figure 2. MCE ME&O Tactics and Strategies

Communications and Media Content

- Social Media
- MCE Website
- Flyers/ fact sheets
- Print and digital advertisement
- Direct mailings
- Email blasts

Grassroots Outreach

- Community Events
- Workshops and Webinars
- Collaboration with Community Leaders

CBO Partnerships

- Joint outreach
- Funding support

Program Leveraging

- MCE Energy Storage Program(s)
- MCE low-income solar program
- MCE LIFT pilot
- MCEv program
- Other CA and local programs

5. METRICS TRACKING

Because MCE is using multiple tactics for ME&O, a variety of metrics will be used to evaluate the effectiveness of each effort. Our primary measure of effectiveness is the number of customers reached, which can be measured by:

- Total number of enrollees in both the DAC-GT and CS-GT programs;
- Total CARE and FERA enrollment achieved through DAC-GT/ CS-GT outreach;
- Total number of customers reached;
- Diversity in race, age and income of event participants, with participation that reflects census distribution demographics of the DAC communities;
- Direct mail and email - email click-through and open rates;
- Indirect website visits and page views, social media engagement and impressions;
- Total number of events and distribution of events by neighborhood.

By regularly monitoring these measures, MCE will be able to make changes in its approach or shift the mix of ME&O channels to improve the effectiveness of outreach, if necessary. Additionally, feedback from CBO partners, surveys, on-the-ground interactions, and message testing could alter the strategy pursued.

MCE

MARIN COUNTY | NAPA COUNTY | UNINCORPORATED CONTRA COSTA COUNTY
BENICIA | CONCORD | DANVILLE | EL CERRITO | LAFAYETTE | MARTINEZ | MORAGA
OAKLEY | PINOLE | PITTSBURG | RICHMOND | SAN PABLO | SAN RAMON | WALNUT CREEK

May 11, 2020

The Honorable Senator Dodd
State Capitol, Room 4032
Sacramento, CA 95814

Re: SB 862 (Dodd)—Support

Dear Senator Dodd,

On behalf of Marin Clean Energy (MCE), I write in support of SB 862, which not only strengthens the ability of local and state governments to timely respond to Public Safety Power Shutoffs (PSPS events), but more equitably protects our most vulnerable populations.

SB 862 would require utilities to include in their wildfire mitigation plans protocols that specifically address the needs of Access and Functional Needs (AFN) individuals. It is imperative that AFN individuals are explicitly included in the utilities' wildfire mitigation plans because they face life-threatening conditions during PSPS events. By expanding existing protocols to account for their safety and well-being, this bill aligns with MCE's values of providing customers with safe and reliable electricity.

As part of MCE's own efforts to support AFN individuals and vulnerable communities during PSPS events, over the coming months MCE will explore ways to provide support for zero-emissions resiliency and backup power to vulnerable customers and facilities that provide critical support for communities during PSPS events. In doing so, we are proud to support and learn from independent living centers and other organizations serving people with disabilities. Additionally, MCE has applied to become a community outreach partner with PG&E to help ensure that Self-Generation Incentive Program Equity Budget funds, which focus on equity and resiliency, reach the households in our service territory that could most benefit from adopting battery storage. MCE believes these efforts along with the requirements spelled out in SB 862 will go a long way toward ensuring that the impacts of 2019's PSPS events on vulnerable and AFN individuals and communities are never repeated.

Additionally, this bill would expand the definition of a "sudden and severe energy shortage" in existing law to include PSPS events. Doing so would accomplish two significant improvements to wildfire preparedness:

1. It would ensure that AFN customers can receive backup electrical resources from electrical corporations without disqualifying them from receiving resources as provided in the Emergency Services Act (ESA).
2. It allows for a State of Emergency and a Local Emergency to be called if a PSPS event is declared, which would help to proactively summon additional emergency resources and personnel to high-risk areas.

MCE appreciates the opportunity to weigh in on this piece of legislation and is pleased to support. If you have any questions, feel free to contact me at (415) 464-6040.

Sincerely,

Shalini Swaroop

Shalini Swaroop
General Counsel and Director of Policy, MCE

CC: Honorable Members of Senate Committee on Energy, Utilities and Communications

MARIN COUNTY | NAPA COUNTY | UNINCORPORATED CONTRA COSTA COUNTY
BENICIA | CONCORD | DANVILLE | EL CERRITO | LAFAYETTE | MARTINEZ | MORAGA
OAKLEY | PINOLE | PITTSBURG | RICHMOND | SAN PABLO | SAN RAMON | WALNUT CREEK

May 8, 2020

The Honorable Senator Hueso
State Capitol, Room 4035
Sacramento, CA 95814

Re: SB 1403 (Hueso)—Support

Dear Senator Hueso,

On behalf of Marin Clean Energy (MCE), I write in support of SB 1403, which would amend the Public Utilities Code to define "low-income customers," pursuant to Section 50093 of the Health and Safety Code, as households at or below 80% of their Area Median Income (AMI).

SB 1403 will allow more low-income individuals and families to benefit from programs that help weatherize their homes and upgrade to more efficient appliances. These investments will help customers use less energy, which saves customers money and reduces the state's greenhouse gas emissions. These investments are all the more important given the current shelter-at-home orders and the dire economic circumstances facing so many low-income households as a result of COVID-19.

Because of California's high cost of living, the current definition of low-income customers – households at or below 200% of the Federal Poverty Guidelines (FPG) – excludes many families that are struggling to make ends meet. In fact, because the guidelines for affordable housing eligibility are based on AMI, in many parts of California families that live in affordable housing are unable to qualify for low income energy assistance because they earn slightly more than 200% FPG. This gap in eligibility for low income assistance has led MCE to include a request to move from an FPG-based income threshold to an AMI threshold in its Low Income Families and Tenants Application, currently pending before the California Public Utilities Commission.

MCE appreciates the opportunity to weigh in on this piece of legislation and is pleased to support. If you have any questions, feel free to contact me at (415) 464-6040.

Sincerely,

Shalini Swaroop

Shalini Swaroop
General Counsel and Director of Policy, MCE

CC: The Honorable Members of Senate Energy, Utilities and Communications
Consultants Nidia Bautista, Sarah Smith