Regulatory Packet

Part 1

November 19, 2020

TO: MCE Board of Directors

FROM: Shalini Swaroop, General Counsel & Director of Policy

RE: Policy Update on Regulatory Items

Dear Board Members:

Below is a summary of the key activities at the California Public Utilities Commission (CPUC) impacting Community Choice Aggregation (CCA) and MCE.

I. California Public Utilities Commission

a. Integrated Resource Planning

On September 1, 2020, MCE and other Load Serving Entities (LSE) filed their individual Integrated Resource Plans (IRP) describing planned resource build-out and associated GHG emissions over the 10-year planning horizon. On September 24, 2020, the CPUC issued a Scoping Memo and Ruling (Scoping Memo) setting the issues and procedural schedule for the current IRP proceeding. The Scoping Memo describes the CPUC's anticipated approach for aggregating the LSEs' individual IRP portfolios; identifies issues that will drive additional mandated procurement for LSEs; and considers whether the IRP cycle should be 3 years instead of the current 2-year cycle. In evaluating the individual LSE IRPs, the CPUC will focus on: (1) ensuring the portfolios achieve the state's reliability and GHG-reduction requirements; (2) whether LSEs' IRPs indicate plans to procure sufficient resources to replace the Diablo Canyon Nuclear Power Plant scheduled to come offline in 2025; (3) planning for long-lead time resources such as Long-Duration Storage, out-of-state wind, and off-shore wind; and (4) analyzing the level of urgency for retiring the state's gas-fired generation fleet. The CPUC expects to issue rulings regarding IRP aggregation, collective LSE resource deficiencies, and incremental procurement need in mid-to-late 2021.

b. Resource Adequacy

On November 2, 2020 MCE submitted its annual 2021 Year-Ahead Resource Adequacy (RA) Compliance Filing to the CPUC. This annual compliance filing demonstrates whether an LSE has purchased its assigned quantity of system, flexible, and local resource adequacy capacity for the upcoming year, or in the case of local resource adequacy, its assigned local capacity for both 2021 and 2022. MCE was able to fully meet its 2021 Year-Ahead RA compliance requirements, including meeting the full 2-year forward local RA compliance requirement by successfully procuring the assigned local capacity in each local capacity area. This compliance filing maintains MCE's track record of meeting all RA compliance requirements to date.

c. PG&E's 2021 Energy Resource Recovery Account Application

On October 30, 2020, MCE coordinated with northern California CCAs to file an Opening Brief in Pacific Gas and Electric Company's (PG&E) 2021 Energy Resource Recovery Account (ERRA) Forecast proceeding. This proceeding will set the Power Charge Indifference Adjustment (PCIA) rate for 2021. The CCAs' Opening Brief argued to: (1) reduce PG&E's requested 2021 PCIA revenue requirement by $265 million; (2) increase the transparency of PG&E's ERRA accounting practices in an effort to better understand PCIA volatility and identify accounting errors that inappropriately increase the PCIA revenue requirement; and (3) obtain timely access to ratepayer funding for MCE's Disadvantaged Community Green Tariff and Community Solar Green Tariff programs that MCE expects to launch in 2021.

d. PG&E's 2019 ERRA Compliance Proceeding

On October 22, 2020 MCE entered into a Settlement Agreement with PG&E and other stakeholders to resolve all but 2 issues in PG&E's 2019 ERRA Compliance proceeding. If adopted by the CPUC, the settlement will correct at least $175 million in errors that will be credited back to CCA customers and reduce PG&E's PCIA revenue requirement. If the settlement is adopted by the end of 2020, CCA customers may see the credit reflected in the 2021 PCIA rates. If not, the credit will off-set PCIA rates in 2022.

On October 26, 2020, MCE coordinated with northern California CCAs to file an Opening Brief in this proceeding to address the 2 issues that remain in dispute. The disputed issues are worth approximately $26 million and will likely be resolved on a similar timeframe as the Settlement Agreement.

e. Microgrids

i. Track 2

On July 23, 2020, the CPUC issued a Ruling and Staff Proposal (Staff Proposal) for Track 2 of the Microgrid proceeding. The Staff Proposal describes CPUC staff's recommendations as to which issues are within Track 2's scope. The Staff Proposal recommends: (1) allowing Investor Owned Utilities (IOU) to install microgrids as Special Facilities; (2) allowing customer-sited microgrids to extend to adjacent parcels; (3) developing a microgrid rate schedule; (4) developing a microgrid pilot program; and (5) conducting pilot studies on low-cost electrical isolation methods.

MCE, in collaboration with other CCAs, is engaged in Track 2 and is focusing on microgrid tariff development.

ii. Track 1

MCE is also monitoring and responding to advice letters filed by PG&E in response to directives under Track 1 of the Microgrids proceeding. MCE filed protests and responses to PG&E's advice letters requesting PG&E: (1) conduct grid resiliency workshops with local governments; and (2) implement PG&E's Community Microgrid Enablement Program.

f. Energy Efficiency

i. CPUC Amended Scoping Ruling

On July 3, 2020, the CPUC issued an Amended Scoping Ruling (Ruling) in the Energy Efficiency (EE) proceeding. The Ruling expresses the CPUC's concern about the Covid-19 Pandemic's impact on ratepayer-funded EE programs and the EE industry in general. The Ruling amended the proceeding's scope and schedule to include evaluation of the pandemic's impacts on the EE industry in California. MCE and other EE Program Administrators (PA) are also directed to file new EE Business Plan Applications by September 1, 2021, which is approximately 3 years sooner than under the original Business Plan schedule.

MCE is working with the CPUC, other EE PAs, and stakeholders to develop the appropriate procedures, requirements, and timelines for the re-filing of the EE Business Plans. The CPUC is expected to issue a Guidance Decision in Spring 2021.

ii. EE Annual Budget Advice Letter

On September 1, 2020, MCE filed its EE Annual Budget Advice Letter (ABAL). The ABAL requests approval of MCE's proposed 2021 EE budget of $7,563,643. The CPUC is reviewing the filing, and MCE expects CPUC approval of its 2021 budget by the end of the year.

g. Transportation Electrification

On September 11, 2020, MCE coordinated with other CCAs to file comments on a CPUC Staff Proposal detailing a Transportation Electrification Framework (TEF). The TEF is the strategic 10-year plan to foster and scale up transportation electrification (TE) in California by implementing ratepayer-funded TE programs and pilots. The CCAs' comments requested that CCAs be authorized to become TE Program Administrators with the same roles and responsibilities as IOUs for future TE programs under the TEF.

This filing was the culmination of coordination efforts among several interested CCAs to establish CCA interest in administering ratepayer funded TE programs. The CCAs continue to engage with stakeholders and the CPUC to build support for the request. The CPUC is expected to issue a Proposed Decision on the issue by the end of 2020.

JULY FILINGS

**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.	)))))	R.12-11-005 (Filed November 8, 2012)

**RESPONSE OF MARIN CLEAN ENERGY TO
CALIFORNIA ENERGY STORAGE ALLIANCE'S PETITION FOR
MODIFICATION OF DECISIONS 20-01-021 AND 16-06-055**

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July 10, 2020

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.	R.12-11-005 (Filed November 8, 2012)

RESPONSE OF MARIN CLEAN ENERGY TO CALIFORNIA ENERGY STORAGE ALLIANCE'S PETITION FOR MODIFICATION OF DECISIONS 20-01-021 AND 16-06-055

In accordance with Rule 16.4(e) of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE")[1] hereby submits the following Response to the California Energy Storage Alliance's ("CESA") June 10, 2020 Petition for Modification of Decision ("D.") 20-01-021 and D.16-06-055 (the "PFM").

I. INTRODUCTION AND BACKGROUND

MCE supports the PFM subject to the amendments discussed below. The PFM asks that the Commission: 1) modify the Self Generation Incentive Program ("SGIP") program rules set forth in D.20-01-021 and D.16-05-055 to allow SGIP program administrators ("PA") to immediately transfer funds between technology incentive budgets through the filing of a Tier-2 advice letter; and 2) modify the D.16-06-055 lottery prioiritzation criteria to reflect the Commission's current prioiritzation of equity and resiliency customers.[2] MCE supports

[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 Contra Costa, Marin, Napa, and Solano counties.

[2] PFM at 2.

modifying the SGIP program rules to allow the immediate transfer of funds between budgets, but asks that the Commission only allow "early" transfers that: 1) shift funds from lower-priority incentive budgets to higher-priority incentive budgets; and 2) shift funds within incentive budgets for the same technology type. MCE supports modifying the lottery prioiritization criteria, but asks that the Commission adopt the clarified new criteria provided below.

MCE has a significant interest in the success and optimal implementation of SGIP. MCE's service area includes many Tier-3 and Tier-2 high fire threat districts ("HFTDs"), and MCE serves many of the communities that have been most impacted by Pacific Gas and Electric Company's ("PG&E's") public safety power shutoff ("PSPS") outages.[3] SGIP is one of the most important programmatic tools available to achieve the State's environmental, resiliency, and equity goals – goals that are central to MCE's mission. In furtherance of these goals, MCE has taken a number of steps to support SGIP. MCE recently launched an Energy Storage Program that provides performance-based payments in addition to SGIP funds to the most vulnerable customers and the critical facilities that support these customers. MCE has also taken steps to educate its customers about SGIP and recruit eligible customers to the program. MCE has developed a *Community Outreach Plan for the Self-Generation Incentive Program's Equity and Equity Resiliency Budget*, a comprehensive plan for MCE's SGIP-related marketing, education, and outreach ("ME&O").[4]

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[3] To date, approximately 35% of MCE's customer base has experienced at least one PSPS event, and many of these customers have suffered *multiple* PSPS outages. MCE is dedicated to implementing programs that reduce the impact of PSPS outages on its customers.

[4] MCE provided a copy of this Plan to the Commission in its March 2020 Protest to Pacific Gas and Electric Company's ("PG&E") advice letter 4219-G/5765-E.

II. RESPONSE TO PETITION FOR MODIFICATION

A. MCE Supports CESA's Proposal To Allow PAs To Transfer Funds Through A Tier-2 Advice Letter Before December 31, 2022 With Modification

Currently, D.20-01-021 prohibits the transfer of SGIP program funds between technology incentive budgets until after December 31, 2022.[5] MCE shares CESA's concern that this prohibition may prevent the efficient allocation of program funds in the 2020-2022 timeframe, and may ultimately limit the program's ability to ensure that as many customers as possible can increase their resiliency as quickly as possible in the face of PSPS events. When D.20-01-021 was adopted in January 2020, the SGIP Equity Brogram was severely underutilized and it was difficult to predict what impact the modifications to the equity incentive levels, and the creation of the equity resiliency budget, would have on program uptake. This is reflected in the fact that the Commission did not allocate any of the new SB 700 funds to the Large-scale Equity Budget, and allocated only 3% of these funds to the Residential Equity Budget.[6]

Thanks in large part to the Commission's, stakeholders', and industry's focus on making SGIP a success and improving customers resiliency in the face of PSPS events, circumstances have radically changed over the past few months. As CESA outlines in its PFM, real-world claims (both approved and waitlisted) in the SGIP Equity Budget greatly exceeded expectations (and available budgets) within the first days of program opening, leading to a large amount of waitlisted projects in both the Large-Scale and Residential Equity Budgets.[7]

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5 D.20-01-021 at 96 (Conclusion of Law 34).

6 D.20-01-021 at 98-99 (Ordering Paragraph 4).

7 The PFM notes that, as of its filing date (June 10, 2020), the Non-Residential Storage Equity budget, currently allocated $52.8 million, was oversubscribed by over $300 million; the Residential Storage Equity budget, currently allocated $31.6 million, was oversubscribed by $8.4 million; the Small Residential Storage budget, currently allocated $60 million, was undersubscribed by $41 million; and the Equity Resiliency budget, currently allocated $612.4 million, was undersubscribed by $458 million. As program enrollment has continued since the PFM's filing, all subscription numbers have likely increased.

The immediate oversubscription of the Large-Scale and Residential Storage Equity Budgets constitutes significantly changed circumstances that undermine the primary justifications for the reallocation freeze. D.20-01-021 finds that "[s]uspending allocation of new large-scale energy storage equity budget funds *until such time as demand increases* supports the prioritization of 2020 to 2024 funds to equity resiliency budget customers."[8] Thus, the freeze on shifting funds to the Large-scale Energy Storage Equity Budget is premised, in part, on the assumption that demand for this program will need time to ramp up – an assumption contradicted by the the immediate over-subscription of the Large-scale Equity Budget.

While MCE generally supports fund shifting requests before December 31, 2022, two limitations should be considered by the Commission. First, MCE agrees with the Commission that it is important to keep SGIP budget allocations as stable as possible to clearly signal available funding to developers.[9] However, this consideration is mostly relevant to the shifting of funds between different technology incentive buckets (e.g. shifting funds from the renewable generation technology category to the energy storage category or vice versa). Shifting funds between budget categories within the same technology type changes only the types of customers that vendors will be dealing with, not the overall demand for the technology, and thus should have minimal impact on developers. Thus, MCE supports clarifying that early transfer requests (requests before December 31, 2022) may only shift funds between incentive buckets <u>for the same technology type but between different customer types</u> (e.g. from the "General Market" Energy Storage Budget to the Equity Storage Budget). The Commission should continue to prohibit the transfer of funds between different technology types (e.g. from renewable generation

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8 Id. at 82 (Finding of Fact 7) (*Emphasis added*).
9 Id. at 59.

incentive budget to any of the storage incentive budgets) until after Deember 31, 2022. MCE believes that this would maintain the intent of the Commission's decision to keep incentive budgets for technology types stable through 2022 but would also allow flexibility to provide incentives for those customers type who have the greatest appetite and/or ability to participate in the SGIP.

Second, MCE recommends that fund transfers be limited to transfers from lower-priority incentive budgets to higher-priority incentive budgets, with priority determined based on the number of Commission policy goals that the program serves:

- Tier 1 (highest priority): Equity Resiliency Budget (meets Commission's environmental, equity, and resiliency goals).
- Tier 2: Equity Budget (meets Commission's environmental and equity goals).
- Tier 3: SGIP "General Market" Budget (meets Commission's environmental goals).

This would allow the PAs to request transfers of funds from the General Market Storage Budget to the Storage Equity Budgets, while protecting higher priority budgets (i.e. the Equity Resiliency Budget). In light of the critical need to increase resiliency and reduce the impact of the PSPS outages and similar disasters for the most vulnerable populations, and the critical facilities that serve those populations, MCE does not support allowing PAs to transfer funds from the Equity Resiliency Budget to other budget categories immediately. Instead, MCE recommends that this restriction remain in place until at least six months from the initial release of the SB700 funds to the Equity Resiliency Budget to see how the demand for the program develops. If substantial funding remains in the Equity Resiliency Budget by February 2021, the Commission should consider allowing fund transfers from the Equity Resiliency to the Equity

Budget to allow as many customers as possible to participate in SGIP before the 2021 fire season.

B. MCE Supports The PFM's Proposal To Modify The SGIP Lottery With Modification

MCE agrees with CESA that the SGIP lottery prioritization criteria adopted in D.16-06-055 need to be updated. However, instead of the specific criteria recommended by CESA, MCE recommends that the following priority-based lottery criteria be adopted:

a) Customers (including critical facilities and infrastructure) that meet the storage equity resiliency criteria.

b) Customers that meet the storage equity criteria.

c) Customers that meet the "general-market" storage criteria.

This prioritization ensures that preference is aligned with SGIP program priorities and customer and community needs.

III. CONCLUSION

MCE appreciates the Commission's consideration of the matters addressed herein.

Dated: July 10, 2020

Respectfully submitted,

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

Application of Pacific Gas and Electric Company for Approval of Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for 2021-2026 Program Years. (U39M)	Application 19-11-003
And Related Matters.	Application 19-11-004 Application 19-11-005 Application 19-11-006 Application 19-11-007

COMMENTS OF MARIN CLEAN ENERGY ON ENERGY DIVISION STAFF PROPOSAL

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BEFORE THE PUBLIC UTILITIES COMMISSION
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Application of Pacific Gas and Electric Company for Approval of Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for 2021-2026 Program Years. (U39M)	Application 19-11-003
And Related Matters.	Application 19-11-004 Application 19-11-005 Application 19-11-006 Application 19-11-007

I. Introduction

As directed by the *Administrative Law Judge's Ruling Seeking Comments*, issued June 25, 2020, Marin Clean Energy ("MCE") respectfully submits the following comments on the *Energy Division Staff Proposal (Final) – June 2020 Energy Savings Assistance Program Goals for Years 2021-2026* ("Staff Proposal"). MCE appreciates the direction the Staff Proposal sets forth for the Energy Savings Assistance Program ("ESA"), and believes that with thoughtful planning, ESA can achieve deeper energy savings while still maintaining its essential role as an equity and hardship reduction program.

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 serves approximately 1,000 MW of peak load and provides generation services to more than 1.1 million people in 34 communities across Contra Costa, Marin, Napa, and Solano counties.

MCE's Low Income Families and Tenants ("LIFT") Pilot has been providing low income multifamily residences in its service territory with energy efficiency and building electrification upgrades since October 2017. In this consolidated application, MCE is applying to be a Program Administrator for the ESA Multifamily Whole Building Program, thereby expanding its LIFT pilot to a full, permanent program.

II. MCE Response to Questions Posed in the Staff Proposal

Below, MCE offers responses to as many of Staff's questions as possible, including the questions directed toward Investor Owned Utilities ("IOUs"). Because LIFT operates differently from the IOUs' ESA programs in several key ways, MCE's perspective on how to reach and effectively serve the ESA target population can provide significant insights to Staff and to the California Public Utilities Commission ("CPUC" or "Commission") as it considers the future of ESA post-2020.

Segmenting the ESA Population

1. *All Parties: Given the goals laid out in the Energy Division Staff Proposal (Staff Proposal) and suggested segmentation approach, how should the IOUs prioritize customer segments for treatment? Which customer segments have an immediate need and are the most vulnerable to climate change/bill impacts/energy use and should be treated first?*

MCE asserts that ESA should not prioritize customer segments for *treatment*, to ensure that the opportunity to participate in the program is available to all eligible customers. However, it may be appropriate to prioritize certain customer segments for *marketing and outreach*, so that extra steps are taken to promote participation by customer segments most in need of the benefits energy efficiency upgrades can deliver.

Given that the financial hardships faced by low-income Californians are growing more severe during the COVID-19 pandemic, it seems prudent to focus ESA marketing and outreach efforts toward customers with significant arrearages, or who would be at risk of disconnection but for the current disconnection moratorium. Additionally, it would be reasonable to prioritize ESA marketing and outreach toward communities experiencing disproportionate respiratory harms, namely

Disadvantaged Communities ("DACs")[1] and the communities in and near High Fire Threat Districts ("HFTDs"). Energy efficiency, weatherization, and building electrification can all improve respiratory health for residents, by removing health hazards inside the home and ensuring that external hazards do not infiltrate the building. These benefits are especially important for communities that are disproportionately exposed to air pollution and wildfire smoke.

2. *All Parties: How can the Staff Proposal's suggested segmentation approach be used with the proposed auditing tool to recommend the most appropriate treatment among the three-tiered options? Are there other tools or approaches that would simplify program delivery to low-income households?*

MCE urges staff to think of the treatment tiers set forth in the staff proposal as guideposts along a spectrum of treatment options, rather than as a menu of options for each property to choose from or be assigned to. An audit will identify, for each property, what measures will improve the building's energy performance, and which will be the most cost-effective. The program administrator/implementer can then work with the customer to identify all of the programs and incentives for which the customer is eligible. Last, the property owner can then determine which recommended upgrades can be undertaken, given the owner's budget after incentives.[2]

These steps will result in a package of retrofits with a savings forecast that will fall into one of the three tiers. As such, the key step in determining the tier into which a particular property's retrofit would fall is the audit, rather than customer segmentation information. As discussed above in response to Question 1, MCE believes that segmentation is most useful for determining how to prioritize program marketing and outreach.

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[1] "Disadvantaged Communities" are the top 25% most impacted census tracts according to the CalEnviroScreen.

[2] The staff proposal contemplates the possibility of property owner co-investment. As discussed in greater detail below in response to Question 18, MCE supports including an owner co-pay option under ESA.

3. *All Parties: How can the IOUs include renter participation in all treatment Tiers?*

In MCE's experience serving renters through both LIFT and its general market Multifamily Energy Savings program ("MFES"), it is critical work with property owners at the outreach and enrollment stage, as well as with tenants. As the decision-makers for the property, not only is owner approval essential, but working directly with the property owner increases the likelihood that the property will undergo a comprehensive whole-building upgrade. This ensures that all tenants of the participating property can benefit. Finally, as discussed further below in response to Question 31, effective tenant protections will be essential to ensure that renters can participate with confidence.

4. *All Parties: The CPUC Affordability Proceeding (R.18-07-006) issued a proposed decision on June 4, 2020 for adopting metrics and methodologies for assessing the relative affordability of utility service. If this proposed decision is approved, how can the customer segmentation process described in the Staff Proposal be coordinated with affordability metrics in this proceeding? Specifically, how can areas with poor affordability metric scores be identified and prioritized for different Tiers of ESA treatments?*

The above-referenced Proposed Decision was adopted at the Commission's July 16, 2020 voting meeting. MCE believes it is appropriate to prioritize communities with poor affordability metric scores for ESA marketing and outreach, and to seek for customers in those communities the combinations of measures and coordinated program incentives that will help them save the most money. Depending on the property and the programs and measures for which it is eligible, the treatment will likely fall into the Strategic or Advanced tier.

As discussed above, MCE cautions Staff against approaching the tiers as discrete packages. The proposed treatment tiers will be extremely helpful in evaluating the ESA program under these new proposed goals, but should not be considered as a static set of measures to be applied to households meeting certain criteria.

Goals, Targets and Metrics

5. *All Parties: The Staff Proposal's Goal #1 for household energy savings is dependent on setting a baseline. Taking into account that the IOUs should be delivering a mix of Tiered treatments, how should this starting value, or baseline, from which to increase by at least 5 percent annually, be calculated? For example, the baseline could be calculated using the average household energy savings value for resource measures (annual kWh and therms per household) for program year 1 or the average savings per household the IOUs proposed in their applications for 2021, or another suggested starting value.*

    a. *Will the minimum 5 percent annual increase incentivize deeper energy retrofits, or are there other components that will?*

    b. *In parallel with, or in place of the proposed 5 percent annual increase, how can the IOUs measure long-term customer value in relation to program costs, similar to the current Lifecycle Bill Savings to Program Cost Ratio metric?*

For the LIFT program, MCE asserts that its current level of savings achieved in the LIFT pilot is an appropriate baseline. The LIFT pilot has been operating since October 2017, and has served to help MCE refine its strategy and approach to the low-income multifamily sector. MCE further asserts that its LIFT 2.0 application already aims for a level of savings that would fall into the proposed Strategic and Advanced tiers. As such, MCE's LIFT application aligns with the Staff Proposal's goal of moving the ESA program toward deeper energy savings.

6. *All Parties: Should the energy savings percentages by Tier (up to 5 percent for Tier 1, 5 to 15 percent for Tier 2, and 15 to 50 percent for Tier 3) remain as guidelines or be set as goals for the IOUs to meet?*

MCE recommends that the energy savings percentages by tier should be established as guidelines, especially in this first program cycle as the IOUs are reconfiguring their programs to meet the newly proposed goals. This question should be revisited in the next program cycle.

7. *IOUs: What is your IOU's estimated average budget per household and estimated average ESA Cost-Effectiveness Test (ESACET) for each of the tiers, and how are these budgets and ESACET averages anticipated to change over time?*

MCE estimates that LIFT 2.0 will be able to treat approximately 4,400 units with a total program budget of $10,603,955. This translates to an all-in per household program cost of $2,410 per unit treated.

MCE is unable to perform ESACET calculations for the LIFT program at this time, as it lacks the capacity to accurately quantify the non-energy benefits needed for the calculation. However, MCE anticipates that because LIFT already offers many of the measures that would be commonly installed in the proposed Strategic and Advanced treatment tiers, the LIFT budget and cost effectiveness scores would not change significantly during the 2021-2026 program cycle.

8. *All Parties: What other targets or metrics should be considered that complement the average treated household energy savings goal? Examples could include, but are not limited to, household bill savings, or greenhouse gas (GHG) reductions.*

MCE recommends adopting a GHG reduction target and metrics for the ESA program. This will help to align ESA with the state's GHG reduction goals, and help program administrators incorporate and track the benefits of fuel switching.

MCE cautions that while tracking household bill savings is important, any analysis of bill savings must bear in mind the impact of ESA's equity measures, which can sometimes increase energy usage. MCE is not opposed to tracking and analyzing bill savings as long as it is done in a manner that is sensitive to these impacts.

Finally, MCE recommends tracking certain key participation demographics, at least some of which are already being tracked. MCE suggests that the proposed customer segmentation characteristics could be a good starting point; for example, rentership/ownership, rural/suburban/urban, single-family or multi-family, whether the property is in a DAC or a High Fire

Threat District ("HFTD"), primary language spoken at home, etc. Tracking participant demographics will help program administrators and the Commission identify communities that are underrepresented among program participants, and target additional outreach and engagement in response.

9. *All Parties: If the average household energy savings goal is based on resource measures only, should a separate goal be set for equity measures? If yes, what is reasonable? What is the best metric, for example, percent of budget spent, to track progress?*

If the Commission elects to adopt a goal for equity measures, MCE submits that the goal should be to bring all eligible customer housing up to a basic standard of health, safety, and comfort ("HSC"). The Commission would need to decide on a baseline standard, as a matter of policy, including considerations such as the ability to keep one's home within a healthy range of indoor temperatures, the ability to keep food in the refrigerator and freezer at a safe temperature, healthy ventilation, a sufficiently robust building envelope, etc.

Progress toward this baseline health, safety and comfort goal could be tracked by assessing how many of the needs identified at eligible customer properties were able to be addressed through ESA's budget for equity measures. This analysis would also help to determine what additional efforts, either within or outside the ESA program, are required to bring low-income housing up to this baseline HSC standard. Additionally, the Commission should explore whether customer satisfaction surveys could provide valuable information on the HSC impacts of equity measures.

MCE also recommends a separate goal for electrification measures. Similar to equity measures, fuel switching will increase a property's electricity usage in order to reduce GHGs. Metrics for tracking progress toward an electrification goal could include GHG reduction, as discussed above, or a simple count of different kinds of fuel substitution measures.

Budget and Costs

10. *All Parties: What cost-effectiveness tests, other than the ESACET, and criteria should be used to evaluate the ESA program as designed under the Staff Proposal? For example, can the Societal Cost Test be an effective assessment?*

MCE has no response to this question at this time. However, as noted above, it remains important to assess the ESA program differently than other energy efficiency programs targeting different customer segments, as the ESACET was designed to do. Because ESA serves some of the state's hardest-to-reach customers, and because it delivers equity measures as well as energy measures, it is appropriate to use tools that account for these unique program features.

11. *All Parties: Refocusing the ESA program on deeper treatments in the next program cycle to maximize per household energy savings may decrease program cost-effectiveness compared to previous cycles. To ensure ratepayer funds are prudently spent, should the CPUC adopt a minimum threshold for program cost-effectiveness, and if yes, what should that threshold be? Should it be a hard goal or soft target?*

MCE urges that, should the Commission elect to adopt a minimum threshold for program cost-effectiveness, it should be designed as a soft target instead of a hard goal. As mentioned above, ESA serves some of the hardest-to-reach customers, which impacts the program's cost-effectiveness. Further, it should be noted that increased program coordination, as contemplated in the Staff Proposal, will increase administrative costs, which could also affect cost-effectiveness. This is especially true if program coordination extends beyond simple referrals. MCE's approach to program coordination is discussed more fully below, in response to Question 18.

Program Design Impacts

12. *All Parties: What other efficiency measures should be considered that are not mentioned in the Tier treatments section of the Staff Proposal?*
    a. *What other non-efficiency measures, such as electrification measures, should be considered?*
    b. *How should the IOUs incorporate electrification measures that may result in GHG reductions but may also reduce average treated household energy savings?*

MCE supports the proposal for ESA to incorporate electrification measures. In MCE's experience with the LIFT pilot, fuel switching for both space and water heating are popular measures among multifamily property owners. While some owners may be motivated at least in part by the GHG reduction potential of electrification, owners also find them highly cost-effective. This is particularly true for properties that need upgrades to both heating and cooling, both of which a heat pump can provide.

As discussed above, MCE recommends a separate set of goals and metrics for electrification, to ensure that the prospect of increased electric usage does not disincentivize electrification and the GHG reduction benefits it can deliver. In addition to GHG reduction goals and metrics, the Commission should consider whether it would be possible to accurately identify the reduction in gas usage resulting from electrification measures, to provide context for the increase in electric usage.

13. *All Parties: What level of training is needed to transition existing ESA contractors to implement Tier 2 and 3 treatments?*

MCE has no response to this question at this time. However, MCE emphasizes that workforce education and training ("WE&T"), for the existing ESA workforce is a critical component of the transition proposed by Staff, and must be planned and budgeted for accordingly. Not only is workforce education and training important for ensuring that eligible customers and communities are well served, but it will also support much-needed local economic recovery once work in homes can safely resume.

14. *All Parties: How can ESA program measures support other high priority needs/objectives of state/CPUC/customers? For example, can efficiency measures be designed to exceed building fire safety codes for resiliency purposes? In particular, are there ways that envelope insulation (floor/wall/roof) measures take fire protection beyond code?*

Senate Bill 32 (2017) established California's current GHG reduction target of reducing emissions 40% below 1990 levels by 2030.[3] Additionally, SB 350 (2015) established a statewide goal

[3] Health and Safety Code Section 38566.

of doubling energy efficiency savings by 2030. Both of these critical state policies will be supported by the Staff Proposal's increased energy savings goals, and by incorporating electrification measures into ESA.

In addition to these critical goals, the state has undertaken a number of efforts designed to reduce peak demand and the emissions associated with natural gas peaker plants. These efforts include time-of-use ("TOU") pricing, and demand side management and demand response programs and incentives. In support of these efforts, MCE proposes to incorporate demand response and demand management technologies into its LIFT program, along with energy education designed to help customers succeed on TOU rates. Such technologies, especially if they allow for automated demand response, will support peak demand reduction in addition to helping participating customers save money. MCE recommends that the Commission consider more meaningfully incorporating demand response technologies into ESA.

15. *All Parties: When significant home repairs are necessary, such as when knob and tube wiring is present, what maximum amount per household is reasonable? Should the ESA program have a program-wide cap or set aside for home repairs for each service territory, such as an amount (for example, $1 million per year, allocated by IOU) or a percentage (for example, 5% of the overall budget)?*

MCE has no response to this question at this time.

<u>Program Coordination Questions</u>

16. *All Parties: How can program data be shared effectively amongst program implementers, including those that are administered by the IOUs as well as non-IOUs like CSD? What barriers exist?*

Protecting customer privacy is of paramount importance in any proposal to share customer data between program implementers. Sharing data beyond the IOU and CCA, if applicable, that serve the customer would require customer consent and non-disclosure agreements. Additionally, different programs may track different data, according to the individual needs of the program. Finally, different databases and other systems can make sharing data between program implementers difficult.

17. *All Parties: What metrics should the IOUs track for coordination and leveraging of other programs?*

Regarding coordination and leveraging of other programs, the ESA program could track metrics such as:

- Non-ESA programs leveraged, and how often they are leveraged;
- Incentive amounts and measures provided through other programs; and
- The additional energy savings, HSC, and GHG reduction benefits accruing to the participating property as a result of program coordination (not to be attributed to ESA, but rather to measure the impact of program coordination on top of benefits provided by ESA).

18. *All Parties: From an ESA customer perspective, which programs are highest priority to coordinate with ESA, and why? From a ratepayer perspective, which programs are highest priority to coordinate with ESA, and why?*

MCE submits that coordinating ESA with solar and storage programs should be a high priority. Energy efficiency is an essential precursor to solar and storage, to ensure that systems are right-sized to the building's more efficient load. As discussed above in response to Question 14, it is also important to coordinate with demand response programs, to help customers succeed on TOU, as well as reduce the need for peaker plants. As long as these efforts are reasonably cost effective, MCE asserts that they will be in both the customer's and the ratepayer's interest.

The staff proposal also raises the prospect of an optional property owner co-investment,[4] as part of its Equity guiding principle. In MCE's experience with the LIFT pilot, which is limited to affordable multifamily housing, the vast majority of property owners are willing and able to invest in the project to some degree. Introducing this option for properties that are able and interested benefits both participating customers and ratepayers in general. An owner co-investment helps to stretch ratepayer dollars further, by introducing another complementary funding stream. It will also allow

[4] Staff Proposal at p. 3.

participating properties to invest in a more comprehensive upgrade, which benefits participating tenants as well as property owners.

Finally, MCE also urges Staff to consider how program coordination happens, in addition to identifying the programs with which ESA should coordinate. In MCE's experience with LIFT, which focuses heavily on leveraging multiple programs for each participating property, MCE has found that the more the program can do "behind the scenes" to assist participating customers, the easier it will be for customers to participate in multiple clean energy programs. MCE's LIFT program takes this approach by taking on the work of identifying all available programs and incentives for which each property would be eligible, processing rebate applications, and other back-end program participation tasks. MCE has found that while this requires more administrative resources, it is more effective than simple referrals at ensuring that participating properties can take advantage of all available opportunities.

19. *All Parties: How can the IOUs participate in, and coordinate with other programs, agencies, and organizations to develop workforce education and training and development opportunities targeted to Disadvantaged Communities?*

MCE urges the ESA program to focus on connecting residents in DACs and other underserved communities to existing WE&T opportunities, which are available in many, though not all, target communities. Where there is an unmet need, in particular communities or in certain sectors or technologies, the ESA program administrators should collaborate with WE&T agencies and organizations as needed to support a solution. MCE has found great success with this approach in LIFT and other of its customer programs.[5]

Especially as the economic recovery from COVID begins, many government, educational,

[5] For more information, please see MCE's blog post entitled *Investing in Sustainability Careers: Training & Job Creation through Local Partnerships*, available at https://www.mcecleanenergy.org/news/training-job-creation-through-local-partnerships/.

and nonprofit entities will all be working toward the goal of putting people back to work, especially in the most economically impacted communities. The most effective and cost-effective approach the ESA program can take toward this end is to support and connect to existing efforts, and help inform partner agencies and organizations about emerging needs in energy efficiency and building performance.

20. *All Parties: What services and programs listed in the Program Coordination section should be targeted to existing or new customers at risk for non-payment or disconnection? In addition, what services should be targeted to segments or zip codes with the highest disconnection rates?*

For customers at risk of disconnection or having trouble paying their bills, ESA program administrators should focus on the services and programs that will save the customer the greatest amount of money. In this approach, it is important to consider the customer's costs holistically, beyond just their current energy bill. For example, a customer that drives an old, fuel-inefficient car and spend a lot of money on gas could qualify for substantial electric vehicle and charging incentives that could make an EV more economical than their current car. What will save each customer the most money will be highly dependent on their individual home and circumstances.

In addition to targeting money-saving energy upgrades toward customers and communities most at risk of disconnection, the Commission should also consider ways to target workforce education and training to these communities. Finally, the Commission should consider ways to effectively deliver energy education in target communities, ideally in partnership with trusted local community-based organizations ("CBOs").

21. *All Parties: How can the IOUs promote low-income and affordable broadband programs in order to better leverage energy management technologies as part of Tier 2 – Strategic Treatments?*

The ESA program can include information about affordable low-cost broadband options as part of energy education. Additionally, low cost phone and broadband programs could be included in the universal application proposed by Staff, if it is created.

22. *All Parties: How can the IOUs leverage their existing relationships with Community Based Organizations (CBOs) and solicit feedback in order to meet the goals?*

    a. *Can CBOs assist with the universal application in its development or use?*

In MCE's experience, CBOs are an invaluable source of information on the communities they serve, and their expertise should be leveraged as program administrators are designing their new ESA offerings. They will help program administrators understand the target audience, which is critical to designing programs that will actually work for the communities they are intended to serve

Specific to the universal application proposal, given the success of the CARE capitation program it is reasonable to expect that CBOs would play a significant role in helping customers use the universal application system and explaining how it works. As such, CBO input should be central to the design of the system, to help ensure that the system is easy for them and for customers to use, make sure the language is clear and the interface is user friendly, etc.

Universal Application System

23. *All Parties: As part of Goal #3, Staff is proposing a universal application system that allows low-income households to complete one application in order to receive services from multiple programs, starting with CARE/FERA and ESA, but potentially including other clean energy programs administered by the IOUs, and other state agencies (for example, CSD) and third-parties.*

    a. *Please address the feasibility of creating a universal application system for CARE/FERA/ESA programs statewide.*
        i. *What are the steps to design and build such a system, and what are the key barriers (such as data sharing) that would need to be overcome?*
        ii. *How should the CPUC determine the benefits and costs of creating a statewide universal system?*

    b. *Please address the feasibility of creating a universal application system across CARE/FERA/ESA programs statewide and other low-income programs.*
        i. *What other low-income programs should be included in the universal*

application system, and should they be incorporated in a particular order?

ii. *What are the steps to design and build such a system, and what are the key barriers (such as data sharing) that would need to be overcome?*

iii. *How should the CPUC determine the benefits and costs of creating such a system?*

iv. *What procedural steps should the CPUC take to incorporate input of stakeholders from all impacted low-income proceedings?*

Regarding determination of the costs and benefits of the system, it will be important to consider 1) the decreased administrative burden, and 2) the increase in customer uptake for each program that can be accessed through the universal application. It stands to reason that customers are more likely to apply to multiple programs if they can do so through a single application than they would be if they needed to complete a separate application for each program.

CCA programs should be among the first programs to be incorporated into the universal application system, because CCAs have a direct relationship with their customers, just as IOUs do. CCAs offer programs that are designed to layer with, or fill gaps between, what their IOU offers. Further, CCAs and IOUs already have extensive data sharing arrangements in place, which will help facilitate incorporation into the universal application. Additional programs that could be incorporated into a universal application could include:

- Solar on Multifamily Affordable Housing ("SOMAH")
- Low Income Home Energy Assistance Program ("LIHEAP")
- Weatherization Assistance Program ("WAP")
- Low Income Weatherization Program ("LIWP")
- Low income EV charging and vehicle incentives
- Lifeline
- Low cost broadband programs

Budget and Costs

24. *All Parties: The CPUC more than doubled annual ratepayer collections for ESA, from approximately $157 million in 2008 to approximately $368 million in 2012, in order to achieve the statutory goal of treating all willing and eligible customers by 2020 pursuant to SB 695 (Kehoe, 2009). Budget increases starting in 2009 were based on the number of willing and eligible households not yet treated in each IOU service territory multiplied by the average cost of treatment per household in that territory. The Commission recognized in D.19-06-022 that the IOUs were on track to meet the 2020 treatment goals and that the next phase of the*

ESA program would be different. In their applications for program years 2021-26, the IOUs proposed to maintain ratepayer collection levels at approximately $432 million per year on average.

a. *Post-2020, what criteria should the CPUC use to determine appropriate ratepayer collection levels for ESA?*

b. *Should the CPUC return ESA ratepayer collections to pre-SB 695 levels following completion of the 2020 treatment goal? If not, please address what budget level is needed to achieve ESA program goals once all willing and eligible homes have been treated and avoid low-income ratepayer burden.*

c. *How would reducing 2021-26 annual budgets from the levels proposed by the utilities to pre-SB 695 levels impact the following:*
    i. *CARE and non-CARE rates*
    ii. *Average bill savings per customer*
    iii. *Lifecycle bill savings divided by total budget*
    iv. *Total energy savings divided by total budget*
    v. *Program-wide ESACET*
    vi. *GHG emissions reductions from the program*
    vii. *Health, comfort, and safety components of the program*

d. *While there is not a CPUC or ESA requirement to maintain a constant ESA workforce, it is appropriate to consider a transition plan to avoid abrupt change to contractors. How would reducing the budget in 2021-26 impact them? What steps could the CPUC, IOUs, and contractors take to mitigate any negative impact (for example, workforce programs designed to help ESA contractors pivot to work on other clean energy programs)?*

e. *Would reducing ESA ratepayer collection levels adversely impact other CPUC programs that may have been forecasting a certain level of energy use reduction due to ESA? Please be specific.*

The Commission should consider deferring the above questions regarding reducing the ESA program budget to the next program cycle, as the decision should be informed by how this first program cycle under the new program goals progresses. The Commission will learn a lot by 2026 about the costs and benefits of the proposed program changes, and both it and stakeholders will be much better positioned to offer informed opinions at that time.

f. *How is the COVID-19 pandemic likely to impact demand for ESA services in 2021-26? How should the CPUC factor in that impact when determining appropriate ratepayer collection levels for ESA?*

It is difficult to predict how the COVID-19 pandemic will impact demand for ESA services in 2021-2026. Most notably, it is impossible to predict when it will be safe to resume work in customers' homes, and when customers will feel comfortable having work done in their homes. As such, it may not be possible for the Commission to consider the impact of the pandemic in its determination regarding ratepayer collection levels for the 2021-2026 ESA program cycle.

25. *All Parties: How do ESA annual ratepayer collections compare to annual ratepayer collections for other CPUC clean energy programs serving low-income customers (e.g. SOMAH, SGIP)? How do they compare to annual ratepayer collections for the general energy efficiency budget (including breakdown of categories, such as codes and standards, etc.)? How do they compare to ratepayer-funded low-income energy efficiency programs in other states or jurisdictions?*

MCE has no response to this question at this time.

26. *All Parties: Public Utilities Code Section 382(a) requires that ESA be "funded at not less than 1996 authorized levels based on an assessment of customer need." What were the major findings of the most recent Low-Income Needs Assessment, and how should they inform the CPUC's determination on ESA ratepayer collection levels for program years 2021-26?*

The 2019 Low-Income Needs Assessment ("LINA") focused on CARE post-enrollment ("PE") processes; CARE marketing, education and outreach ("ME&O"); ESA health, safety, and comfort impacts; alternative fuels customers' hardships; and low service reliability customers' hardships. Its findings were not directly relevant to the question of ratepayer collection levels for ESA.

27. *All Parties: IOUs have historically spent significantly less than their authorized annual ESA budgets. What measures should the CPUC adopt to improve estimates of budgetary needs moving forward?*

MCE has no response to this question at this time.

Multifamily

28. *IOUs: For the IOU's proposed Multifamily Whole Building Program, what criteria will the IOUs put forward in the solicitation process to achieve deeper energy savings? How does the proposed solicitation process follow Public Utilities Code 327(b)?*

MCE has not yet finalized its solicitation criteria for its LIFT program for 2021-2026. When its criteria are finalized, MCE will seek qualified program administrators with experience delivering deep energy savings in low-income multifamily housing.

As a CCA, MCE is not subject to PU Code Section 327(b), which applies only to electric and gas corporations. However, the criteria set forth in Section 327(b) are closely aligned with MCE's goals for LIFT and its mission as a local public agency. MCE does not anticipate any reason why its final solicitation criteria would diverge meaningfully from the criteria set forth in Section 327(b). For additional information, please see MCE's Sustainable Workforce Policy, which has been formally adopted by MCE's Board of Directors and is applicable to all MCE procurement, contracting, and hiring.[6]

29. *All Parties: If a peer review group is created for the Multifamily Whole Building Program solicitation process, who should serve or be represented in this group?*

MCE has no response to this question at this time.

30. *IOUs: There are substantial differences among the IOUs on such issues as serving the deed-restricted and non-deed restricted and seeking statewide versus regional bids from implementers. Do these differences create barriers for owners with properties in multiple service areas or where gas is provided by one IOU and electric by another? If the program remains for deed-restricted properties only, and these customers typically own many properties across the state in their portfolios, is a statewide program the best option? Why or why not?*

While the several program administrators differ in their approaches to certain issues, these differences do not necessarily mean that a statewide program is the best option. A single statewide

[6] Available at https://www.mcecleanenergy.org/wp-content/uploads/Policy-011-MCE-Sustainable-Workforce-Policy-v3.pdf.

program stifles innovation, whereas a regional program structure allows different program administrators to test different approaches, and to focus on the approaches that best meet the needs of their communities. Where program administrators overlap geographically, customers benefit from the ability to choose between those different approaches.

To address the concerns raised in this question, the ESA program could set a baseline or statewide standard on certain key issues. This would provide the kind of consistency across programs that this question seeks, without limiting options or stifling innovation.

31. *All Parties: How can non-deed restricted housing owners be held accountable to ensure that the property is not "flipped" or that rents are not raised once the ESA retrofits are completed?*

MCE encourages the Commission to consider models from other states as a starting point toward serving tenants in non-deed restricted housing, upon which California can build. MCE believes that requiring the owner to sign an affidavit limiting rent increases for a period of years after the retrofit is complete, is a good starting point. The affidavit should carry some financial penalty, such as a clawback penalty that requires the owner to repay program costs if the rent increase restrictions are breached. MCE plans to employ these mechanisms, at a minimum, for all NOAH properties that LIFT serves. Additionally, MCE will monitor such properties to ensure that the tenant protection agreement is not breached, so that the enforcement burden is not left solely to tenants.

MCE emphasizes that this is just a starting point, and program administrators and stakeholders should monitor the program's expansion to NOAH properties and refine renter protections as needed.

CARE/FERA

32. *IOUs: Discuss, in detail, whether the budgets proposed to update existing probability models should be augmented and/or reallocated in light of COVID-19.*

MCE has no response to this question at this time.

33. *IOUs: Discuss, in detail, whether recent Athens data in filed February 2020, should be updated to account for COVID-19 impacts and the associated economic downturn resulting in significant increases in the estimated eligible population.*

MCE has no response to this question at this time.

34. *IOUs: Provide a count of households in your service territory that have been enrolled in CARE/FERA for 5 or more years consecutively but never approached or participated in ESA and propose an outreach plan and strategy to effectively target this population and mitigate this program participation gap?*

MCE has no response to this question at this time.

35. *IOUs: Propose an outreach plan and strategy to effectively target and address specific counties with CARE penetration levels below 70 percent and in zip codes that experience the highest disconnection levels (in the top 10th percentile).*

MCE has no response to this question at this time

36. *All Parties: How can marketing, education, and outreach materials for CARE/FERA reference the California Lifeline program (enabling income-qualified customer access to broadband services) and other low-income programs?*

MCE believes that eligible customers would benefit from the inclusion of Lifeline and other low-income programs to CARE and FERA marketing materials. Especially if the universal application is created, marketing materials for low income programs can seamlessly direct customers to that single point of entry for multiple programs.

III. Conclusion

MCE commends the vision set forth in the Staff Proposal and appreciates the opportunity to provide these comments on it. MCE looks forward to supporting the ESA program as it evolves in this program cycle and beyond.

Respectfully submitted,

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AUGUST 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.	R.17-09-020

CALIFORNIA COMMUNITY CHOICE ASSOCIATION INFORMAL COMMENTS ON THE LOCAL CAPACITY REDUCTION COMPENSATION MECHANISM

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August 3, 2020

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION
INFORMAL COMMENTS ON LCR COMPENSATION MECHANISM

The California Community Choice Association (CalCCA)[1] submits these informal comments on the issues identified in Decision (D.) 20-06-002 to update and summarize its proposal for designing the Resource Adequacy (RA) Central Procurement Entity (CPE) Local Capacity Requirement (LCR) Reduction Compensation Mechanism (RCM). CalCCA's initial proposal, presented in its July 20 informal comments, has evolved through discussions with other parties individually and in the July 27 workshop. Based on workshop feedback, CalCCA has narrowed its proposal to focus on one of the options included in its initial comments. These comments (1) discuss the challenges presented in designing an RCM around the principles discussed in D.20-06-002; (2) present responses to the questions directly posed by the Commission for the WG; and (3) summarize CalCCA's overall proposal.

I. INTERPRETING D.20-06-002

Discussions among the parties at the workshop raised questions regarding the boundaries prescribed by the Commission for RCM design. CalCCA thus identifies Commission directives on key issues and some of the challenges in integrating these directives.

For reference, CalCCA lists below the directives of D.20-06-002 relevant to RCM design.

<u>Effectiveness:</u>

1. The RCM cannot provide a "one for one" premium as CalCCA proposed without considering effectiveness. [p.41]

2. The RCM must address "local effectiveness" and "use limitations" of the shown resource…. [O¶ 5.d.]

3. The WG should consider how to adjust payments to an LSE "from year to year to account for changes in the effectiveness of the resource reducing local requirements." [O¶ 5.d.]

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[1] California Community Choice Association represents the interests of 20 operational 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 José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

4. CPE selection criteria must include (1) "Local effectiveness factors, as published in the California Independent System Operator's Local Capacity Requirement Technical Studies" [O¶ 14.b.] and "Energy-use limitations" [O¶ 14.h.]

Least-Cost, Best-Fit:

5. "Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSEs seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE" [p. 42 and O¶ 5.d.]

6. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]

Premium Determination:

7. The RCM should "only compensate[] LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs" [p.43]

8. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]

9. A "benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums" [p.42]

10. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]

11. The WG must determine "[h]ow to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices." [O¶ 5.b.]

In addition to these directives, the Commission rejected CalCCA's proposal for a one-for-one credit with ex post pricing based on the average price paid by the CPE for resources in the local area for which a resource is shown. It directed that "[a]n 'LCR reduction compensation mechanism' departs from CalCCA's must-take, local price based proposal." [p. 43] CalCCA interprets this directive as foreclosing reliance on: an ex post price; an average of bid prices accepted by the CPE; and a premium that ignores effectiveness and use limitations.

From these conclusions, CalCCA gleaned the boundaries to guide its proposal. The RCM must (i) have a pre-determined, rather than ex post, price premium; (ii) account for "local effectiveness" and "use limitations"; (iii) avoid the influence of "market power inflated price premiums"; and (iv) compare the premium "alongside" bid resources to evaluate the overall cost effectiveness of the CPE portfolio. While the Commission indicated that the premium "may" be cost-based, it did not foreclose a market-based premium.

CalCCA worked within these boundaries despite certain challenges, some of which are discussed below. A foundational principle, however, lacks clarity. D.20-06-002 did not make clear whether shown resources, even after adjusting for effectiveness and use limitations, would be "must take" or whether they could be rejected by the CPE if the RCM formula did not result in the most cost-effective CPE portfolio. While the Commission did not foreclose a must-take structure *provided* that it accounts for effectiveness and use limitations, CalCCA's proposal nonetheless takes the most conservative reading of the decision: the CPE may reject a shown resource on cost effectiveness grounds. This approach gives more weight to the importance of a least-cost, best-fit portfolio and ratepayer value and substantially simplifies implementation.

II. RESPONSES TO D.20-06-002 QUESTIONS

1. How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?

Addressing effectiveness and use limitations was one of the most difficult challenges in designing an RCM. As discussed in CalCCA's July 20 comments, D.20-06-002 essentially asked the WG to develop a methodology that neither the CAISO nor the Commission, to date, has been able to develop. CalCCA nonetheless framed two approaches to assessing these factors, which were presented at the workshop and are discussed below. Critically, however, CalCCA's proposal summarized in Section IV does *not* require an express determination on either factor; instead, it relies on the CPE to assess them in evaluating the shown resource's value. Whatever methodology the CPE applies to bid resources to assess effectiveness and use limitations will be equally applied to shown resources.

a. Methodologies Considered by CalCCA

CalCCA presented two possible methodologies at the workshop to evaluate effectiveness and use limitations. Both methodologies, however, require substantial additional development to implement and, even then, will provide only very rough justice.

Method 1: CAISO Local Effectiveness Factors

D.20-06-002 directs the CPE must consider in selecting resources in its solicitation the local effectiveness factors found in the California Independent System Operator (CAISO) Local Capacity Technical Report and Operating Procedure 2210Z. [O¶ 14.h.] These factors are stated as a percentage effectiveness for each existing resource in a local area. One approach thus would be to apply these factors, stated in percentages, to reduce the MW of shown capacity. The reduction would need to be scaled; CalCCA considered scaling the shown resource's factor to the average of the factors for resources selected by the CPE in a local area.

While CalCCA believes that this approach could be used to provide some indication of the relative value of shown vs. bid resources, no party advocates using this approach. CalCCA believes that it would require development of potentially rigid selection criteria that may not align with the criteria needed for the CPE to assess the value of both shown and bid resources. In short, CalCCA does not believe this is approach would produce reasonable premiums. The CAISO has made clear, several times, that the published factors were not intended to be used in this manner. Indeed, the published factors represent a resource's effectiveness in resolving the "highest" constraint in the area, among potentially dozens of constraints. So, for example, one resource might be highly effective in addressing the top constraint but completely ineffective in addressing another, and another might not be effective in addressing the top constraint but is highly effective in addressing 19 other constraints. Relying on the published factors would give full credit to the first resource and no credit to the other resource –an incomplete and inequitable result. In fact, as one IOU commenter noted during the July 27 workshop, it is highly unlikely that the CPE will apply these factors quantitatively but will consider them qualitatively among other resource characteristics. Reliance on CAISO's published effectiveness factors to scale the shown resource MW will not fully or fairly represent a resource's locational value.

Method 2: Addressing Use Limitations

CalCCA also considered a technology-specific approach to address use limitations. The CPE could develop a factor for battery storage by comparing the battery storage duration of the shown resource to the duration of the resources selected by the CPE in the local area. If the CPE selected any four-hour batteries in an area, a four-hour shown battery would receive 100% credit. Alternatively, if the CPE selected no four-hour batteries in an area, the CAISO LCTR provides other potential avenues of assessing battery use limitations, including the data underlying LCTR Table 3.1-3 to compare a shown resource's storage duration to the CAISO-determined storage duration required in the local area. This approach, however, requires a consideration of the baseline underlying those required durations and interpretation of the overall data. Implementation, if possible, would require additional time and might in the end provide only rough justice to a shown resource.

A different approach would be needed for solar, wind, and hydro generation. PG&E identified, and CalCCA considered, relying on the LCTR's assessment in each local area of a resource type's contribution to the peak hour in the area. For example, PG&E pointed to the CAISO's assessment of the Sierra LCR area load and resources. [LCTR p. 42] The LCTR states that the "estimated time of local area peak is 19:10 PM," and ISO-metered solar output at the time is 2.0 percent. While the methodology was not discussed in detail, presumably PG&E intended to multiply storage MW of capacity in the Sierra area by 2 percent to adjust the MW to which the premium price would be applied. Unfortunately, this information is not provided for all local areas (*see, e.g.,* North Coast and North Bay LCR, p. 32). Further, this approach would not apply to wind and hydro resources, and separate methodologies would need to be developed.

Overall, a piecemeal approach to evaluating use limitations might be possible. Additional development would be required, however, and the result, again, would provide only rough justice to shown resources.

b. CalCCA Proposed Approach

CalCCA proposes that shown resources be compared for selection by the CPE alongside bid resources, subject to a pre-determined price cap, to ensure a least cost, best fit solution. Consequently, neither the premium nor the MW shown would be discounted. Like bids, if the CPE selects the resource, the resource owner will get the pre-determined price for the MW of NQC provided; if the CPE rejects the bid, the resource owner will get nothing. CalCCA's proposal thus leaves the question of how to evaluate effectiveness and use limitations to the CPE's process used for bid resources. As long as the CPE applies its selection criteria for both shown and bid resources in a non-discriminatory manner, LSEs can use the showing mechanism to make their local resources available to the CPE without having to participate in the CPE solicitation process.

2. How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas)?

CalCCA proposes a premium for each local area or sub-area to ensure that the shown resources are reasonably valued and have a reasonable opportunity to "compete" with bid resources in the same local area. The premium would be set at a more aggregated level if required to mask prices of individual resources.

CalCCA's proposal makes any other granularity, such as technology, unnecessary. The CPE will consider all of these factors in evaluating both shown and bid resources using the criteria mandated by the Commission for selecting resources from the solicitation.

3. How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices.

CalCCA proposes development of a premium that will be published annually. The premium would be calculated as follows:

> <u>Year 1</u>: Use the median price from the last two quarters of Energy Division PCIA responses for both system and local RA; subtract system price from local RA price and multiply by effective MW
>
> <u>Subsequent Years</u>: Use the median price from the last two quarters of Energy Division PCIA responses for system RA and the most reported CPE solicitation results for local RA price; subtract system RA price from local RA price and multiply by effective MW

There would be little risk to the market of publishing the premiums determined using this methodology. The system prices ultimately will be published within a year in the annual Energy Division RA Report, so there is little or no risk in revealing these prices. Making the median CPE price in the prior solicitation public also presents little risk. The median reveals nothing about the stratification of bids around the median, nor does it illuminate bid prices for bundled system/local RA resources.

4. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process.

CalCCA proposes that an LSE must choose between the bid and show options. Allowing a resource to show a resource at the pre-determined price but later revoke its showing if it is able to do better in the bid solicitation process is difficult to rationalize. Why would the CPE choose a resource in the bid process that has been made available through showing if the bid price is higher than the pre-determined price? To make this choice would be contrary to ratepayers' interests. Conversely, why would an LSE ask for less in the solicitation than it could otherwise garner through a showing? Even aside from these complications, allowing an LSE to both bid and show would require further implementation rules regarding the timing and sequencing of these elections. For these reasons, the Commission should reject the bid *and* show approach.

PG&E has proposed a variant of this approach: if an LSE chooses to show but not bid, it may receive the local premium at the pre-determined price; if an LSE bids and later shows when not selected in the solicitation process, the LSE may do so but may not receive the local premium. While there is a reasonable basis, from a ratepayer value standpoint, to adopt this approach, it creates questions around the CPE solicitation. If the CPE knows in advance that the LSE will show at no cost if its bid is not selected, why would the CPE under any circumstances select the bid? From a ratepayer standpoint, it would add unnecessary cost. This approach, however, could distort the bid solicitation process and create conditions that disadvantage non-LSE bidders.

5. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

As with other questions, CalCCA's proposal simplifies the response to this question. The CPE is highly unlikely to adjust bid prices from year to year for resources selected in the solicitation. It will pay the price bid for the term proposed or it will reject the bid; the notion of accepting a bid subject to future modification is antithetical to the normal IOU solicitation process. Likewise, since the CPE will be comparing the shown resources alongside the bid resources, the same principle should apply. Either the CPE accepts the resource at the price and term shown, or it rejects the resource; there is no right to modify in the future as effectiveness changes. In short, there is no need under CalCCA's proposal to develop an annual effectiveness adjustment for shown resources.

6. How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?

This question seems unrelated to the working group's purpose and should be addressed holistically in the development of the CPE's bid evaluation criteria. CalCCA observes, however, that if a gas and preferred resource produce roughly equal value in all respects (a highly unlikely scenario), the CPE should be bound to select the preferred resource.

7. In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.

CalCCA proposes to provide the premium to LSEs who have shown their existing local RA attributes to the CPE. "Existing contracts" should be defined as contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued). The premium should be provided for the lesser of the remaining contract term and the end of the 2025 RA compliance year.

The IOUs propose to grant eligibility to utility-owned generation (UOG) under the "existing contract" provision. Their proposal falls unambiguously outside of the intent of D.20-06-002. CalCCA's interpretation of the decision rests on the following Commission directives:

- "For existing local <u>contracts</u>, including gas <u>contracts</u>, a working group process is established in Section 3.5 to consider treatment of these existing <u>contracts</u>." [p. 41]
- "The working group should submit a proposal on the treatment of existing <u>contracts</u>, which may include consideration of whether any proposed LCR reduction compensation mechanism should be applied to existing contracts." [p. 46]
- "The working group directed in Ordering Paragraph 5 shall also consider and submit a proposal on the treatment of existing <u>contracts</u>, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing <u>contracts</u>." [O¶ 6.]

The decision, in other contexts, distinguished IOU UOG and contracts. It stated: "[i]t is also reasonable for the IOU to bid its resources into the CPE's RFO, including utility-owned generation (UOG) or contractually committed resources that are not already allocated to all benefitting customers, at their levelized fixed costs, and we direct the utility to do so when it is acting as the CPE." [p. 48]

The Commission also set clear parameters on the choices an IOU has for its resources. It directed: "A distribution utility acting as the CPE should bid its own resources into the solicitation process at their levelized fixed costs." It also specified: "A distribution utility shall have the same options as other load-serving entities in deciding whether to bid or show its resources into the central procurement entity's solicitation process." [COL 14.] In other words, the IOU will be able to show its preferred resources or energy storage to the CPE, just as other LSEs. The IOUs should also be able to show existing fossil contracts, subject to the terms and conditions discussed in CalCCA's proposal above.

III. OTHER DESIGN ISSUES

D.20-06-002 did not address the term of a resource showing. CalCCA proposes that LSEs be permitted to show for up to whatever term is allowed for bid resources, recognizing that the term it shows will affect the CPE's evaluation of its value. The term start date could be any year within the three-year forward CPE compliance period.

CalCCA also proposes requiring a showing, like a bid, to be documented through a confirm under the Edison Electric Institute (EEI) Master Agreement. Shown resources should have the same level of commitment to the CPE as any bid resource.

IV. SUMMARY OF CALCCA PROPOSAL

In response to the presentations and discussion at the July 27 workshop, CalCCA proposes the following framework for the RCM.

Shown Resources Compared Alongside Bid Resources	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources
Annual Price Update	If selected, LSE will be paid the pre-determined price for the shown resource without annual adjustment for effectiveness
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose
Calculation of Payment	If selected, LSE will be paid the pre-determined price for the shown resource
Premium Granularity	Local area or sub-area unless aggregation up is required to mask individual resource prices
Showing Term	LSE may show a resource for a term of up to three years, with the term commencing within the current three-year compliance period
Bid/Show Election	LSE may show or bid its resource, not both
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show for the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing “resources” do not qualify for a local showing.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U 39 E)	Application 20-07-002

PROTEST OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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August 5, 2020

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Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U 39 E)	Application 20-07-002

PROEST OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Pursuant to Rule 2.6 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California (Commission), the California Community Choice Association (CalCCA) hereby submits this protest to the above-captioned *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)* (Application).

CalCCA protests the Application on the grounds Pacific Gas & Electric Company (PG&E) has not demonstrated the relief it requests is just and reasonable,[1] complies with all applicable rules, regulations, resolutions and decisions for all customer classes, including but not limited to Decision (D.) 18-10-019, D.19-10-001 and D.20-02-047 (the 2020 "ERRA Forecast Decision"), and prevents illegal cost shifts between bundled and unbundled ratepayers.[2] The magnitude of impact on the departing load customers warrants a process that enables full and

[1] *See*, Cal. Pub. Util. Code § 451.
[2] Cal. Pub. Util. Code §§ 366.2(f)(2), (g).

timely review of the Application. PG&E's proposal will increase the Power Charge Indifference Adjustment for departing load customers, including CCA customers between 5% and 12% for the 2009 to 2018 vintages, with a small decrease for the 2019 vintage. The final increase to the PCIA, revenue requirement and rate impacts are likely to be substantially greater than those currently in the Application given the current status of the Portfolio Allocation Balancing Account year-end balance in PG&E's June 2020 Monthly Report.[3] That June 2020 Report includes a year-to-date PABA undercollection of $1,073.0 million, nearly *double* the $537.8 million projected as the year-end PABA balance in the Application (prior to the application of an ERRA-related credit). In sum, the actual relief PG&E is requesting in this docket, including both the revenue requirements and the final rates proposed, does not yet appear in the Application and will not be known until PG&E completes all *four rounds of supplemental testimony* it has requested, including the crucial November update testimony (November Update).

Recognizing that this further testimony -- particularly PG&E's November update -- will be pivotal to the rates ultimately adopted, CalCCA thus is concerned about the ability to effectively review PG&E's proposals in the time provided by the schedule. For this reason, CalCCA supports the Joint CCAs' call for:

- ✓ Cooperation and reduced timelines in discovery for all parties, especially surrounding rebuttal testimony and the November Update;
- ✓ Contemporaneous service of workpapers with any updates to testimony; and
- ✓ Clear presentation of the changes between prepared and updated testimony.

CalCCA also supports the schedule proposed by the Joint CCAs.

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3 *See PG&E Energy Resource Recovery Account Activity Report*, p. 4, "Total PABA Ending Balance" (June 2020).

I. DESCRIPTION OF CALCCA

California's community choice aggregators (CCAs) are local governmental entities that provide electricity services to their residents pursuant to Public Utilities Code Section 366.2. CCAs are currently serving about 10 million customers in more than 170 cities and counties across California.

CalCCA was formed in 2016 as a trade organization to facilitate joint participation in certain regulatory and legislative matters in which members share common interests. CalCCA's voting membership includes CCAs serving load and others in the process of implementing new service, including: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, MCE, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

II. CALCCA'S INTEREST IN THIS PROCEEDING

CalCCA seeks party status in this proceeding to address issues related to the Power Charge Indifference Adjustment (PCIA) rate, which will be set for 2021 in this proceeding. Customers of CalCCA's member CCAs pay the PCIA rate as departing load customers. CalCCA's interests center on whether PG&E has calculated the PCIA consistent with applicable Commission decisions in R.17-06-026, a proceeding in which CalCCA has been an active party. CalCCA is also interested in ensuring consistency of application of the PCIA methodologies across the service territories of all three investor-owned utility service territories where member CCAs provide service.

Certain CCAs serving customers in the Pacific Gas and Electric Company (PG&E) service territory are also participating in this proceeding as "Joint CCAs": East Bay Community Energy, MCE, Monterey Bay Community Power Authority, Peninsula Clean Energy, Pioneer Community Energy, San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy Alliance. Other CCAs in PG&E's service territory may also participate individually. CalCCA intends to coordinate with these CCAs to align interests and participation to the extent possible.

III. GROUNDS FOR PROTEST

CCA is still reviewing the Application and anticipates that it will propound discovery requests and otherwise seek to examine other aspects of the Application. CalCCA thus reserves the right to identify and address other issues that may arise in this proceeding. However, on initial review of the Application, CalCCA joins with the Joint CCAs in protesting the Joint Application on the following grounds.

- Recent experience does not support PG&E's proposed forecast of 10% unsold Resource Adequacy (RA) capacity.
- PG&E continues to use costs from it 2020 General Rate Case (GRC) that have not been approved.
- PG&E's application regarding its Wildfire Expense Memorandum Account (WEMA) does not have a scoping ruling let alone approval for cost recovery.
- Modifications to line loss factors when calculating the indifference amount are currently premature.
- More detail is needed to understand PG&E's projected year-end PABA balance.
- PG&E continues to defy the Commission's Order to implement last year's ERRA Forecast Decision.
- It is unclear whether PG&E calculated the 2020 true-up using GRC Costs that have not yet been approved.

- Adjustments to the 2020 PABA balances to reflect agreed-upon changes in PG&E's 2019 ERRA Compliance case should be included in the 2020 true-up, including credits for prior period interest in the 2020 true-up.
- PG&E's proposals regarding the year-end transfer of ERRA balances may require revision.
- PG&E's proposal to allocate the year-end PUBA Balance to 2021 PCIA rates requires further investigation.
- PG&E should provide COVID-related updates to its load forecasts for 2021 in its Rebuttal Testimony in addition to the November Update.
- PG&E's proposals regarding the modified Cost Allocation Mechanism (CAM) require close scrutiny to ensure all customers only pay those costs attributable to them.

In addition, the Commission will need to address the interaction between this docket, the recently filed ERRA trigger application, A.20-07-022, and any PCIA Undercollection Balancing Account trigger application filed during the pendency of this proceeding.

IV. PROCEDURAL SCHEDULE, NEED FOR HEARINGS, AND CATEGORIZATION OF PROCEEDING

Pursuant to Rule 2.6(d), CalCCA provides the following procedural comments:

A. Need for Hearing

CalCCA anticipates that evidentiary hearings will be necessary to address the issues identified in Section III.

B. Proposed Schedule

CalCCA supports the schedule proposed by the Joint CCAs.

C. Categorization

The proceeding is appropriately categorized as "ratesetting."

V. PARTY STATUS

Pursuant to Rule 1.4(a)(2), CalCCA hereby requests party status in this proceeding. As described herein, CalCCA has a material interest in the matters being addressed in this proceeding. CalCCA designates the following person as the "interested party" in this proceeding:

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VI. CONCLUSION

CalCCA appreciates the opportunity to submit this protest to the Application and requests party status.

Respectfully submitted,

Evelyn Kahl
General Counsel to the
California Community Choice Association

August 5, 2020

Braun Blaising Smith Wynne, P.C.

Attorneys at Law

August 6, 2020

Via E-Mail (EDTariffUnit@cpuc.ca.gov)

Energy Division, Tariff Unit
California Public Utilities Commission
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Subject: **Protest of Marin Clean Energy To PG&E Advice Letter 5882-E**

Dear Energy Division Tariff Unit:

Marin Clean Energy ("MCE") hereby protests Pacific Gas and Electric Company's ("PG&E") Advice Letter 5882-E (the "Advice Letter"). As set forth below, the Advice Letter fails to fully comply with Ordering Paragraph 7 ("OP 7") of D.20-06-017 in violation of Section 7.4.2(2) of General Order ("GO") 96-B. In light of this non-compliance, MCE respectfully requests that the California Public Utilities Commission ("Commission") reject the Advice Letter and direct PG&E to re-file an amended Advice Letter that fully complies with the requirements of OP 7 and D.20-06-017 generally.

PROTEST

A. The Advice Letter Does Not Ensure Effective Internal Communication Processes

OP 7 requires, in part, that the investor owned utilities' ("IOU") Advice Letters "specifically address how the utilities plan to develop and ensure that effective internal communication processes exist for managing interface with local governments ("LGs")[1] government by enumerating how the IOUs will achieve" five listed outcomes, including:

- Designating utility interface roles and responsibilities;
- Managing engagement with local and tribal government and building and sustaining effective relationships;
- Establishing and maintaining open, accurate, and consistent lines of communication;
- Involving local and tribal government in planning and vetting of utility actions impacting local and tribal government; and
- Executing [and follow-through] on agreements impacting local and tribal governments.[2]

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[1] Consistent with D.20-06-017, in this protest MCE uses the term "local governments" or "LGs" to refer to city, town and county governments, tribal governments, and CCA programs.

[2] D.20-06-017 at 120-121 (OP 7).

PG&E's Advice Letter does not adequately address these requirements. It has been well established in both the Microgrids Rulemaking and other dockets, including the Commission's De-Energization Rulemaking (R.18-12-005) that existing channels of communication between PG&E and LGs are inadequate. Improving these deficient channels of communication was a primary focus of Track 1 of the Microgrids Rulemaking and is the primary purpose of OP 7. In this context, it is clear that OP 7 requires that PG&E provide a detailed description of an *improved* communication process, not a reiteration of its existing process.

Regarding the requirement that PG&E designate utility interface roles and responsibilities, PG&E provides a list of four "groups of external engagement representatives assigned to specific regions and agency types… to manage outreach." This list includes Public Safety Specialists, Local Public Affairs Representatives, Tribal Liaisons, and Division Leadership Team Leaders.[3] PG&E's list falls short of satisfying this requirement for three reasons.

First, PG&E identifies and (briefly) describes *existing* groups and job functions, not new points of communication or improved communication processes. In order to "achieve effective internal communication processes" it is critical that PG&E formally create direct points of contact between each of its relevant local/divisional technical departments LGs. Under PG&E's existing outreach model, many communications with LGs are channeled through a small number of designated "gatekeepers" (generally local government, tribal, and CCA liaisons). This model is inefficient and unreasonably restricts the flow of information. Consistent with OP 7, PG&E should be required to amend its Advice Letter to create formal points of contact that allow LG technical staff working on resiliency projects (as well as local/tribal emergency planners and first responders) to communicate and collaborate *directly* with PG&E's technical departments at the division and local levels.

Second, PG&E's list does not include CCA Liaisons, and does not propose improved communications processes with CCAs. D.20-06-017 clearly establishes that CCAs are LGs. All requirements mandating that PG&E improve communication and coordination with local and tribal governments also require that PG&E make the same improvements to its communication and coordination with CCAs.

Third, PG&E does not identify outreach representatives to key local community stakeholders. While OP 7 applies primarily to LGs, it is also important that PG&E improve its communications with key stakeholders. MCE notes that PG&E's webinars/workshops, to date, have been made available to LGs and key stakeholders like telecommunication providers. In addition to critical facilities and infrastructure operators like telecommunication providers, improved resiliency and microgrid-related communications efforts should be extended to community-based organizations and community leaders that can provide a more direct channel to underserved communities. MCE can play a role in bridging the information gap, but more direct

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3 Advice Letter at 4.

engagement with local leaders would ensure that the needs of underserved communities are being raised.

The remainder of the Advice Letter's discussion of internal communications processes is inadequate for similar reasons. Regarding the OP 7 requirement that PG&E manage engagement with LGs and build and sustain effective relationships, PG&E proposes to maintain the status quo – having LGs continue to interact with a "single point of contact" gatekeeper.[4] PG&E thus offers no concrete improvements over the current ineffective communications model.

Similarly, PG&E fails to meet the OP 7 requirement regarding the requirement that PG&E involve LGs in the planning and vetting of utility actions. Addressing this requirement, PG&E merely describes its existing mechanisms for sharing information with LGs.[5] PG&E *does not* propose a formal mechanism for incorporating LGs into the planning and vetting of utility actions. There is a fundamental difference between: 1) "informing" LGs about a utility's plans; and 2) incorporating LGs into the planning process. PG&E has failed to provide a proposal that would incorporate LGs into the planning process, and the Advice Letter would continue PG&E's practice of "talking at" LGs rather than collaborating with them.

B. The Advice Letter's Workshop Proposal Is Not Consistent With D.20-06-017.

Several aspects of the Advice Letter's workshop proposal are inconsistent with the requirements of D.20-06-017. D.20-06-017 explicitly requires that each IOU "conduct semi-annual face-to-face *county-level* workshops to ensure the utilities and local entities are sharing valuable information and taking a collaborative approach to planning grid resiliency measures that are responsive to local needs."[6] In the Advice Letter, PG&E ignores the requirement that the workshops be conducted at the county level, instead proposing to hold semi-annual workshops in each of PG&E's five broad "regions."[7] By providing region-wide rather than county-specific information, this proposal would deny LGs access to the granular local information they need for effective resiliency planning, undermining the fundamental purpose of the workshop requirement. PG&E's proposal would severely limit LGs' opportunity for participation and direct engagement through the workshop process. Each of PG&E's regions includes many counties, each of which has multiple local and tribal agencies, and it is not possible for all of the LGs in an entire PG&E region to have a meaningful dialogue with PG&E regarding their distinct local issues in a two hour workshop involving scores of other LGs.

PG&E's proposed workshop agendas are similarly problematic. PG&E proposes to divide the required workshop subject matter between its semi-annual workshops, addressing electric infrastructure and planned upgrades in one workshop and PSPS criteria and the impact of planned system upgrades on PSPS outages in the second workshop.[8] This is plainly inconsistent

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4 Advice Letter at 4-5.
5 Advice Letter at 5.
6 D.20-06-017 at 46 (*emphasis added*).
7 Advice Letter at 6.
8 Advice Letter at 6-9.

with D.20-06-017, which clearly contemplates that all required information will be covered in each individual workshop:

> …we direct the utilities to incorporate their electrical and distribution investment and operation plans into the semi-annual workshops. This will ensure that the utilities fully communicate and solicit input from local and tribal governments about their portfolio of projects intended to minimize the use of PSPS events. The information communicated should include, but should not be limited to: (1) identifying the projects (as applicable to each utility, i.e., reconductoring, transmission line exclusion, transmission line switching, distribution segmentation, distributed generation enabled microgrids, temporary generation, and substation make-ready); (2) identifying projects by county and providing geographic location; (3) describing scope, schedule, cost, and number of customers impacted by the project; and (4) confirming potential for minimizing customer outages due to PSPS events.[9]

PG&E's proposed bifurcation would mean that LGs would only receive the "complete" set of information required by D.20-06-017 once per year. Having only annual updates to critical planning information will frustrate one of the basic purposes of the workshop requirement – providing LGs with "a transparent understanding of the utilities' planned resiliency upgrades and projects [which] may reduce or eliminate the need for local and tribal government or CCA resiliency projects in some areas."[10]

PG&E's proposed workshop agendas are also lacking in key detail. For instance, in order for LGs to effectively target resiliency projects to mitigate the impacts of PSPS events and other outages, it is critical that PG&E's proposal to provide a PSPS Planning Map Using GIS Mapping Technology be expanded to include the identification and description of the areas that are *most likely* to experience PSPS events in the future. In the past, workshops have focused more on where PG&E is planning on mitigating PSPS events (through sectionalization or system hardening). This information, alone, is not sufficient to allow LGs to optimally target their resiliency programs and investments, as it does not allow LGs to identify the highest outage risk areas that are not being addressed by PG&E's planned mitigation efforts.

Similarly, PG&E's proposed discussion of "Upcoming/ Ongoing Transmission and Distribution Infrastructure Investment for resilience and Operational Plans"[11] must include more specific and detailed information about:

- PG&E's planned and ongoing microgrid projects – including scope, technology, size, deployment schedule, total load to be supported etc. For example, for the 2020 fire season, PG&E has only shared a high-level .pdf to date of which substations may receive a diesel generator during PSPS events. There is no

9 At 47.
10 Id.
11 Advice Letter at 8.

information about the size of the generator, how many and which customers are expected to be covered, when will deployment decisions be made, and how and when LG will be informed about deployment decisions.

- Timelines and status updates for PG&E's planned and ongoing system hardening, wildfire safety, and resiliency projects. For each project, PG&E must specify a timeline for implementation including start and expected end date and the utility must report on any potential delays to these timelines in the next workshops. For example, if PG&E plans to implement a sectionalization effort in Calistoga, the utility must include in the workshop presentation the start date of the actual work and the expected end date, and provide detailed planning and technical materials regarding the project in advance of the workshop. If these dates are not met, justification must be provided why such work was delayed. The same principle applies to other mitigation initiatives and microgrid projects, including but not limited to system hardening, microgrids, back-up generation etc.

PG&E should be required to submit an amended Advice Letter that remedies each of these flaws and omissions.

C. PG&E's Collaborative Planning Session Proposal Should Be Strengthened

PG&E's proposed "Collaborative Enhancing Grid Resilience Planning Session"[12] should be strengthened to include a discussion of local goals/ areas of concerns from two perspectives:

- PSPS planning and impact perspective led by County OES (what areas are most likely to experience PSPS events, which customers are most impacted, where are the critical facilities etc.).

- Microgrid and resiliency project coordination *led by local CCA* (if relevant) – what local, community-scale microgrid projects are being implemented by local CCAs and other LG entities. It is not appropriate for local OES to lead the discussion re microgrid proposals pursuant to the CMEP. Local OES are responsible for emergency response planning and coordinating emergency response during outage events, not implementing microgrids and other resiliency solutions. The local CCA will likely be leading these local projects and should hence be the lead for this section of the workshop. For example, MCE is already in conversation with PG&E staff about the potential development of community-scale microgrids for PSPS mitigation in MCE's service area.

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[12] Advice Letter at 9.

CONCLUSION

For the reasons set forth above, MCE requests that Commission reject the Advice Letter and instruct PG&E to re-file an amended Advice Letter that fully complies with D.20-06-017.

Dated: August 6, 2020

Respectfully submitted,

Shalini Swaroop
General Counsel and Director of Policy, MCE

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Erik Jacobson
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Service List: R.19-09-009

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

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON BACKSTOP PROCUREMENT AND COST ALLOCATION MECHANISMS

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August 7, 2020

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING
SEEKING COMMENTS ON BACKSTOP PROCUREMENT AND
COST ALLOCATION MECHANISMS

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Administrative Law Judge's Ruling Seeking Comments on Backstop Procurement and Cost Allocation Mechanisms* issued on June 5, 2020 (ALJ Ruling) and the June 23, 2020, *E-Mail Ruling Granting the Joint Utilities' Request for Extension for Comments and Proposals in Response to ALJ's Ruling Seeking Comments on Backstop Procurement and Cost Allocation Mechanisms.*

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1 California Community Choice Association represents the interests of 20 operational community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, MCE, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

I. INTRODUCTION

CalCCA replies to the opening comments submitted by Southern California Edison Company (SCE)[2] and Pacific Gas and Electric Company (PG&E)[3] on July 22, 2020, on cost allocation mechanisms and backstop procurement. CalCCA begins with a critical observation regarding cost allocation mechanisms. While SCE and PG&E propose recovering the costs of opt-out and backstop procurement from the *customers* of load-serving entities not satisfying their D.19-11-016 requirements, their comments highlight instead the reasons why these costs should be recovered directly from the *load-serving entities* (LSEs) serving those customers. Their explanations thus support CalCCA's proposal for investor-owned utilities (IOUs) to bill LSEs *directly* for opt-out and backstop procurement to ensure that LSEs remain responsible for the elections they make on behalf of their customers.

To address these and other issues presented by the PG&E and SCE comments, CalCCA recommends that the Commission:

- ✓ Adopt CalCCA's proposal to bill LSEs directly for the procurement undertaken by an IOU on behalf of the LSE's customers, rejecting proposals by SCE and PG&E to bill the costs to customers through a delivery charge.
- ✓ Adopt SCE's proposal to require IOUs to offer all RA, GHG-Free and RPS attributes of opt-out and backstop procurement to LSEs.
- ✓ Adopt SCE's tiered process for backstop procurement, *clarifying* that backstop load-serving entities (LSEs) may first procure excess incremental resources from other LSEs with excess resources and *directing* the IOUs to minimize the term of backstop procurement.
- ✓ Adopt SCE's proposal for a January 1, 2021, Milestone #1 backstop trigger point for Tranches 2 and 3 of procurement, rejecting PG&E's proposed 24-month trigger.

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2 *Opening Comments of Southern California Edison Company (U 338-E) on Administrative Law Judge's Ruling Seeking Comments on Backstop Procurement and Cost Allocation Mechanisms,* July 22, 2020 (SCE Comments).

3 *Response of Pacific Gas and Electric Company (U 39 E) to Administrative Law Judge's Ruling Seeking Comments on Backstop Procurement and Cost Allocation Mechanisms,* July 22, 2020 (PG&E Comments).

- ✓ Modify SCE's proposed material changes to milestone procedures to provide adequate notice of requirements.
- ✓ Reject proposals by SCE and PG&E requiring *full* backstop for any IOU that misses a trigger point for Tranche 1 procurement when that procurement is reasonably delayed and reasonably certain to come online.
- ✓ Reject PG&E's proposal to assign all bundled procurement in response to D.19-11-016 to the 2019 vintage.

II. COST ALLOCATION MECHANISMS

A. Adopt CalCCA's Proposal to Bill LSEs Directly for Opt-Out or Backstop Procurement on behalf of the LSE's Customers

CalCCA proposed that IOUs bill LSEs directly for opt-out or backstop procurement, rather than billing the LSEs' customers through another nonbypassable charge embedded in the IOUs' delivery charges.[4] While PG&E and SCE instead propose recovery from LSEs' customers, their explanations directionally support CalCCA's solution.

CalCCA explained that billing LSEs for the costs of procurement on their customers' behalf (1) is more consistent with the intent of D.19-11-016 to make procurement the responsibility of the LSE making the election; (2) gives all LSEs equal long-term financial responsibility for their procurement obligations; (3) minimizes distortions in presentation of generation charges in the customers' monthly bills; and (4) provides greater administrative ease. CalCCA observed that any perceived credit risk resulting from this approach could be addressed through credit and collateral provisions, socializing the cost in the event of insufficient collateral.

While PG&E and SCE propose to recover the costs directly from the customers of opt-out and backstop LSEs, their comments directionally support CalCCA's proposal.

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[4] CalCCA Comments at 5-8.

- ✓ Both SCE and PG&E recognize that the procurement is the *LSE's* obligation.[5] In fact, PG&E refers to *LSE* cost responsibility[6] and concludes that the costs of procurement on behalf of opt-out LSEs should not follow their customers.[7]
- ✓ SCE acknowledges the competitive distortion in generation rate comparisons that will occur: "LSEs who do their own procurement would reflect all costs in their generation rates, while opt-out LSEs would presumably only reflect the System RA MPB costs (and/or RPS Adder MPB costs as applicable) in their generation rates since the IOUs would be billing the remaining net costs via delivery rates."[8]
- ✓ Both SCE and PG&E acknowledge the distortion in generation charges today on customers' bills;[9] rather than attempting to minimize the impact, however, they propose to further complicate and exacerbate the existing failure of bills to provide "apples to apples" generation cost comparison.[10]
- ✓ PG&E highlights the need for 12-24 months of billing system upgrades and modifications for backstop procurement.[11]
- ✓ SCE agrees with CalCCA that the LSE should enter into a standard contract with the IOU to support payment for RA or RPS attributes it receives, which would be secured by collateral that would pay off any net costs remaining in the event of default or bankruptcy.[12]

Billing LSEs correctly assigns cost responsibility for an LSE's procurement decisions and minimizes any competitive distortions and complexity. The Commission should for these reasons adopt CalCCA's recommendation.

B. Adopt SCE's Proposal to Require IOUs to Offer All RA, GHG-Free and RPS Attributes of Opt-Out and Backstop Procurement to LSEs

SCE proposes to offer all RA and RPS attributes to backstop and opt-out LSEs, and to allocate any GHG-free attributes to these LSEs.**[13]** If LSEs decline their share of RA or RPS

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5 *See, e.g.,* PG&E Comments at 8.

6 *See* PG&E Comments at 13, 14 ("the Opt-Out LSE will be responsible for the full cost of any backstop procurement being recovered through BAM….").

7 PG&E Comments at 16.

8 SCE Comments at 35.

9 *See* SCE Comments at 35; *see* PG&E comments at 15.

10 SCE Comments at 35.

11 PG&E Comments at 17-18.

12 SCE Comments at 34.

13 SCE Comments at 25-26.

attributes, the IOU may choose to retain the attributes for bundled customers or offer them to the market. CalCCA supports SCE's proposal in these circumstances.[14]

PG&E, in stark contrast, proposes to retain all RPS and GHG-free attributes for bundled customers.[15] There is no justification for benefitting bundled customers with attributes paid for by opt-out or backstop LSEs or their customers, and PG&E's proposal should be rejected.

III. BACKSTOP PROCUREMENT MILESTONES

A. Adopt SCE's Tiered Process for Backstop Procurement with Clarifications

SCE proposes a four-tiered process for backstop procurement.[16] First, the IOU will "use any excess resources already under contract with the IOU above its own procurement requirements" and the requirements of opt-out LSEs. Second, the IOU may expand existing contracts on a bilateral basis to meet the backstop procurement need. Third, the IOU may consider bilateral agreements with previously bid but unsuccessful projects. Finally, the IOU may conduct a separate solicitation.

CalCCA generally supports this approach as it carries the potential to minimize the overall costs of procurement in response to D.19-11-016, subject to two clarifications. The Commission should provide that if an LSE defaults to backstop procurement, it should be first given an opportunity to procure compliance resources from other *non-IOU* LSEs before the IOU allocates its own resources. It should also minimize the term of any allocation of excess resources or solicitation if backstop is required as a result of delay, rather than a complete failure to procure.

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[14] CalCCA notes, however, that this approach may not be reasonable in other contexts, such as allocations of Power Charge Indifference Adjustment portfolio benefits.

[15] PG&E Comments at 15.

[16] SCE Comments at 17.

B. Adopt a January 1, 2021, Milestone #1 Backstop Trigger Point for All Tranches

SCE proposes to set the Milestone #1 backstop trigger for Tranches 2 and 3 at January 1, 2021, to provide adequate time for backstop procurement.[17] CalCCA supports this approach as a clearer approach than PG&E's proposed 24-month lead time, which leaves ambiguity around the trigger date for Tranche 2 procurement.[18] While CalCCA appreciates the sincerity of PG&E's efforts to ensure incremental capacity is brought online, it is unreasonable to force LSEs to conclude all procurement 24 months prior to the compliance deadline. As PG&E notes, 24 months represents an aggressive time frame for new resource development *including solicitation, project consideration, contract approval and financing.* LSEs may be several months away from a signed contract while still on track to bring new resources online in time for the compliance deadline. The overlap of incremental procurement with Once-Through-Cooling fossil resource extensions creates a sufficient buffer which provides several additional months (if not 1-2 years) of procurement runway for IOUs to backstop LSE shortfalls.

At this point, however, adopting a September 1, 2020, Milestone #1 trigger point for procurement scheduled to be online on August 1, 2021, is no longer reasonable. SCE has proposed significant changes to the milestone procedures that deviate from the initial proposal provided in the June 5, 2020, Ruling. These changes, if adopted, would require re-negotiation of already executed contracts or changes to contracts deep in negotiations, all of which would have to be accomplished in less than a month's time. Moreover, since a decision on these important questions cannot be issued until after September 1, application of this Milestone #1 as proposed by SCE would be retroactive and provide insufficient notice to enable compliance. For this

17 SCE Comments at 6.

18 *See* PG&E Comments at 2 and 5.

reason, the Commission should set Milestone #1 for Tranche 1 for January 1, 2021, along with the other two tranches, and limit the application of SCE's refinements to contracts executed following the date of the final decision.

C. Modify SCE's Material Proposed Changes to the Milestone Procedures to Provide Adequate Notice of Requirements

SCE proposes substantial changes to the Ruling's proposed milestone procedures and adopting this detail without adequate notice and greater clarity would undermine LSEs' ability to comply. Thus, in addition to shifting Milestone #1 to January 1, 2021 for all Tranches, CalCCA seeks refinement of SCE's proposed changes as described below.

1. Resource Milestone #1

SCE's proposal augments the contracting requirement to require that contracts for new construction "should not be at seller's option or include other **similar terms that allow for easy cancellation**."[19] This limitation could be interpreted broadly towards the termination provisions in a power purchase agreement. "Easy cancellation" has no definition. Moreover, developers can typically "cancel" or terminate a project if they are comfortable forfeiting their development security posting (usually millions of dollars, depending on the project's size and terms in contract) to the buyer. This "easy cancellation" qualification should not be adopted. Including compliance requirements that mandate specific contractual terms at this stage of the procurement process (i.e., nearly a year after LSEs have begun commercial negotiations and/or executed agreements with counterparties) is inappropriate. If the Commission chooses to adopt the qualification, however, this term must be clearly defined and include examples further clarifying what types of contractual provisions the CPUC would deem non-compliant with this

[19] SCE Comments at 8.

requirement. LSEs must also then be given sufficient time to address the newly adopted requirement, which would further support a delayed Milestone #1 for Tranche 1 procurement.

SCE further adds the requirement for Milestone #1 that contracts for new construction must be for a "commercially proven technology." Again, LSEs have received insufficient notice of this potential compliance requirement. Moreover, this term is vague and undefined, and no guidance is provided on what documentation would suffice to demonstrate that a technology is commercially proven. Such a requirement also risks discouraging procurement of newer, desirable technologies. For example, are flow batteries commercially proven? Would SCE's IceBear behind-the-meter technology have met the test when contracted? Finally, this requirement would be very problematic if it were to exclude resources already contracted or nearing execution. CalCCA recommends the Commission not adopt this requirement.

Finally, SCE proposes to require in Milestone #1 that contracts have a "demonstrated path to FCDS by the required online date." CalCCA notes that some projects may only receive Partial Capacity Deliverability Status (PCDS), and requests that projects should still be counted as incremental resource capacity to the extent of their PCDS.

2. Resource Milestone #2

As CalCCA noted in its initial comments "a Notice to Proceed" (NTP) is a notice between a developer and an Engineering, Procurement and Construction contractor determining the date on which work may commence. PPAs do not typically include a requirement for developers to submit NTP documentation to the buyer or LSE. Instead, most PPAs require that the developer submit an executed "Construction Start Date Certificate" or similar affidavit certifying that NTP has been issued and construction of the facility has occurred. CalCCA suggests that the NTP milestone requirement should also be able to be fulfilled by submission of an executed Construction Start Date Certificate or similar contractually-required affidavit.

SCE also proposes in Milestone #2 a requirement that identification of a "Fatal Flaw" will trigger immediate backstop procurement.[20] Once again, "fatal flaw" lacks definition and could create uncertainty in the compliance process. A bankruptcy, for example, would be a clear and unambiguous example of a fatal flaw. If issues are identified due to interconnection or transmission upgrade delays, permitting delays, or Force Majeure, most standard contracts give a "permitted extension" for these delays that are outside the control of both seller and buyer and would not be cause for contract termination. Permitted extensions for these types of circumstances can be twice as long, or more, than SCE's proposed 90-day Force Majeure exception. These types of issues should not be considered "fatal flaws." Likewise, COVID-19 delays should not be considered "fatal flaws." Consequently, if the Commission introduces the "fatal flaw" concept proposed by SCE explicitly into the milestone procedures, it should be very limited to unambiguous failures.

3. Resource Milestone #3

SCE proposes a 90-day remediation period for failing to meet Milestone #3 for Tranche 1 procurement, but limits remediation for Tranches 2 and 3 to only 30 days.[21] SCE argues that "[a] shorter remediation period is appropriate for Tranche 2 and 3 procurement than Tranche 1 because LSEs will have significantly more time to meet the August 1, 2022 and August 1, 2023 online dates than they had to meet the August 1, 2021 online date." While SCE's statement that LSEs will have a longer time to meet the online dates may be generally true, all projects differ, and there may be issues that arise that require more than 30 days to remedy. Moreover, SCE has not adequately justified this compression, omitting any explanation of whether and how failure to meet Milestone #3 for Tranches 2 and 3 places the IOU in a worse position than with Tranche 1.

20 SCE Comments at 15.
21 *Id.* At 15-16.

Without more justification, a 90-day remediation period should be adopted for Milestone #3 for all Tranches.

D. Require Full Backstop Procurement Only When an LSE Materially Fails to Meet Its Milestones

SCE recommends that the Milestone #1 trigger point for backstop procurement for Tranche 2 and 3 procurement be set at January 1, 2021.[22] If this milestone is not met, the IOU would begin backstop procurement.[23] PG&E similarly suggests that if the LSE misses any Milestone, the IOU should commence backstop for all years' requirements.[24]

CalCCA agrees that, in some cases, this may be reasonable, such as if an LSE fails to make any good faith efforts to procure or its efforts are clearly deficient. Materiality, however, is a critical consideration. If, for example, an LSE misses Milestone #1 for 20% of its requirement due to a reasonable delay, it would be unreasonable to penalize the LSE with full backstop procurement for all requirements for all years. The Commission thus should make clear that full backstop procurement will be triggered for LSEs that materially fail to meet Milestone #1. The trigger should occur only if, after prompt discussion with the LSE, the Commission determines the LSE is unlikely to bring its planned resources online in the reasonably foreseeable future.

IV. OTHER ISSUES

A. Reject PG&E's Proposal to Assign All Bundled Procurement in Response to D.19-11-016 to the 2019 Vintage

PG&E proposes to assign bundled customer procurement cost responsibility 100% to the 2019 vintage "because the procurement quantities were allocated based on the load share in that

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22 SCE Comments at 22.
23 SCE Comments at 6.
24 PG&E Comments at 8.

year and for the existing LSEs in that year (e.g., new or expanding LSEs may not have been accounted for in the Decision)."[25] It claims this is a "minor" change. In fact, it is a significant departure from D.19-11-016, which is not proposed by SCE or San Diego Gas & Electric Company (SDG&E), both of whom instead propose to adhere to the direction in D.19-11-016 to collect these costs from departed load via the same approach used to collect from opt-out LSEs. The Commission soundly rejected this proposal in D.19-11-016, and neither SDG&E nor SCE offers a similar proposal. The Commission should reject PG&E's proposal to place all of its procurement track costs in the 2019 PCIA vintage.

The Commission considered vintaging in D.19-11-016 in response to a proposal from SDG&E.

> We also clarify that the capacity procured by the IOUs in response to this decision will be allocated on a non-bypassable basis through a modified CAM mechanism and not PCIA. In other words, we will not reduce the cost allocation amounts to be recovered by the IOUs after load migrates. Thus, we do not make the modifications suggested by SDG&E, in its comments, to account for load migration before or after the CCA or ESP elects whether it will self-provide, or for PCIA vintaging.[26]

Moreover, D.19-11-016 does not support PG&E's conclusion that the allocations were based on 2019 load shares, without adjustment for then-anticipated departing load. Indeed, the Commission "utilized the 2020-year ahead forecasts for resource adequacy capacity" to allocate load shares by class of LSE.[27]

Finally, even if PG&E's factual contention regarding forecast shares were correct, to grant PG&E's request would place CCAs at a disadvantage from the outset. The IOUs would effectively be permitted to adjust their allocations by moving any excess allocation to already-

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25 PG&E Comments at 12-13.
26 D.19-11-016 at 67.
27 D.19-11-016 at 40.

departed load, while CCAs would be forced to charge their customers for any noise in the allocation process.

The Commission should reject PG&E's proposal and, instead, employ the compliant methodologies proposed by SCE and SDG&E.

V. CONCLUSION

For all of the foregoing reasons, CalCCA requests that the Commission adopt the recommendations herein and in CalCCA's opening comments.

Respectfully submitted,

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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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION TRACK 3.B PROPOSALS

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION TRACK 3.B PROPOSALS

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to the *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling* issued on July 7, 2020 (Amended Scoping Memo), offering proposals for consideration in Track B.

I. INTRODUCTION

The Amended Scoping Memo established two general categories of issues for Track 3.B of this proceeding:

- "Examination of the broader RA capacity structure to address energy attributes and hourly capacity requirements;" and
- "Other structural changes or refinements to the RA program identified during Track 1 or Track 2."

CalCCA offers proposals in both categories of issues. Together with Southern California Edison Company (SCE) in comments filed contemporaneously with these comments, CalCCA proposes a general framework to address "energy attributes and hourly capacity requirements" (Modified RA Framework). CalCCA's comments describe its views on the implementation issues that

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1 California Community Choice Association represents the interests of 20 operational 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 José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

must be resolved to implement this framework. CalCCA additionally proposes refinement of the existing resource adequacy (RA) program to include a waiver program for system and flexible RA compliance penalties. As discussed further below, CalCCA initially raised this issue in its Petition for Modification in R.17-09-020 and again in Track 2, where the Commission rejected the proposal identifying further study that would be required prior to its consideration. Consistent with D.20-06-031, CalCCA proposes a design and process for this further study.

II. CALCCA JOINTLY WITH SCE SUPPORTS THE MODIFIED RA FRAMEWORK TO ADDRESS ENERGY ATTRIBUTES AND HOURLY CAPACITY REQUIREMENTS AND RECOMMENDS

SCE and CalCCA's joint Track 3.B Proposal presents a high-level redesign of the RA program to better reflect net peak resource needs and energy resources needs. Consistent with the current RA framework, an extensive list of details and methodologies for development, assignment, and assessment of RA compliance requirements would be required for the new paradigm.

At this stage, the proposal leaves many of these implementation details to a later stage, likely to be resolved in working groups should the Commission endorse further consideration. CalCCA has identified implementation details that require consideration, discussed below.

A. Determination of LSE Compliance Obligations

1. **California Energy Commission (CEC) Load Forecasts:** Currently, the CEC does not forecast load shapes for individual load-serving entities (LSEs). A process for developing LSE-specific load shapes for each LSE will be necessary, with specific consideration to LSE expansion, load migration, LSE-specific weather patterns, and load modifiers.
2. **Transmission and Distribution Losses:** Building an RA compliance obligation up from load may not account for losses incurred on the transmission and distribution system. Further work will be required to ensure collective LSE RA procurement addresses additional capacity and energy required to serve load.
3. **Load Migration:** Further consideration of the impacts of load migration should be taken up in the implementation phase. While structural load

migration (e.g. CCA formation) may occur with sufficient notice and planning for LSEs to incorporate into their showing, intra-year competitive migration (e.g. customer switching from LSE A to LSE B) may result in considerable shifts in the compliance requirement for an individual LSE.

4. **Showings:** Further development of the LSE compliance filing process would be necessary, including the development of templates, establishment of timelines and requirements for LSEs, and other criteria.

5. **Trading:** A structure should be considered to permit trading between LSEs of Net Qualifying Capacity (NQC) and Net Qualifying Energy (NQE) products to ensure a competitive and efficient compliance structure.

B. Determination of Resource Valuations

6. Load Profile of Solar and Wind Resources

As noted in the filing, hourly solar and wind generation profiles from the Integrated Resource Plan proceeding should be used to net contracted solar and wind production against LSE load. Further consideration would be required to determine whether and how to apply these load profiles to future compliance and account for the potential of anomalous weather conditions. Additionally, further work is required to properly account for energy contributions from resources without full deliverability status and otherwise refine the current deliverability construct for this new paradigm. Finally, consideration should be given as to whether a modification to NQE calculation or net duration curve will be necessary to account for on-site charging limitations of hybrid resources subject to the requirements of the Investment Tax Credit.

7. Storage Parameters

A methodology for assigning various parameters to battery resources will be required, including determining round-trip efficiency, storage charging rates, and other criteria. It may be necessary to consider further constraints or methodological revisions to the storage sufficiency test, something which should be examined in tandem with other potential sources of variability within this construct.

8. NQE for Fossil Resources

A methodology for determining NQE for fossil resources will be required in consideration of operational, legal/contractual, environmental, economic, or other constraints to the resources' ability to serve load. The current process for assigning resources an NQC value, which is based on performance criteria, testing and verification, and other restrictions, may be used as a guide for establishing a process for assigning NQE. For fossil resources, special consideration should be given to air quality permits, start/stop restrictions, and other operational constraints.

9. NQE for Hydroelectric Resources

A methodology for determining NQE for hydroelectric resources will be required similar to that required for fossil resources. For hydroelectric resources, special consideration should be given to flow requirements and variations in seasonal and annual water availability.

10. NQE for Demand Response

A methodology to determine NQE for Demand Response should be established, giving consideration to contracted demand response as well as historical energy reductions.

11. NQE for Imported RA

A methodology for determining NQE for import RA contracts will be required and should be constructed based on the energy flows indicated in the contract.

12. Export from Behind-the-Meter Resources

Behind-the-meter resources account for a significant and growing share of energy production. Further work should be pursued to resolve whether, and if so, how to credit LSEs for exported generation from BTM resources controlled by their customers.

C. Addressing Variability and Risk

13. Planning Reserve Margin for NQE and NQC

The current structure addresses variability and risk through the use of a 15% Planning Reserve Margin. Further analysis should be conducted to analyze sources of variability and risk, including anomalous weather, generator unavailability and non-energy uses (e.g. ancillary services), load forecast and temporal mismatches between load and generation. Improved understanding of potential drivers of uncertainty may be gained through statistical analysis, and may be addressed through the establishment of a Planning Reserve Margin.

D. Policy Interactions

14. Resource Allocations

Successful, cost-effective implementation of this policy is contingent on improving the current process for LSE allocation of resources. While resource allocations are currently limited to a relatively small share of resources on the Cost Allocation Mechanism (CAM) list, the CAM list is expected to grow considerably following the implementation of the Local Resource Adequacy Central Procurement Entity. Further, a pending co-chair report in Power Charge Indifference Adjustment (PCIA) Phase 2 Working Group 3 proposes to reallocate investor-owned utility (IOU) renewable and RA resources to LSEs (upon their election) in lieu of the current PCIA structure. Both of these proceedings will have dramatic effects on LSE resources and needs; resolving these proceedings and improving the timeliness and accuracy of allocation forecasts will be necessary to avoiding costly overprocurement.

15. IRP Reliability Assessment

Further development work will be required to integrate the Integrated Resource Planning (IRP) and RA processes, with particular focus on how these policies align and provide the right incentives for LSEs to bring on and retain a set of resources capable of serving the needs of the electric system. In particular, further work will be required to consider whether the three prongs of this proposal should be incorporated as metrics within the IRP proceeding.

III. CALCCA PROPOSES FURTHER STUDY OF LEANING AND MARKET POWER ISSUES TO FACILITATE CONSIDERATION OF A SYSTEM AND FLEXIBLE RA WAIVER PROCESS

A. The Commission Left the Door Open for Consideration of a System and Flexible RA Waiver Process in this Track

CalCCA submitted a Track 2 proposal to include a system and flexible RA waiver process like the waiver process employed today for local RA compliance.[2] CalCCA first filed its system and flexible RA waiver proposal in its Petition for Modification in R.17-09-020.[3] The proposal was resubmitted as a Track 2 proposal at the informal suggestion of Staff considering the transfer of outstanding issues from R.17-09-020 to R.19-11-009. In D.19-06-026, the Commission expressed support for "further discussion of these issues through workshops or in a later phase in this proceeding".[4] While Track 2 should have provided that venue, practically there was limited opportunity for such a discussion and the proposal was rejected due to remaining open questions. However, CalCCA believes that Track 3.B is now the appropriate forum to address these issues as the Commission left room for further study to pursue such a process.[5]

Several parties opposed CalCCA's system and flexible RA waiver proposal.[6] The Western Power Trading Form (WPTF) argued that "a waiver process requires rigorous study of

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2 *California Community Choice Association's Late-Filed Track 2 Proposal*, Mar. 18, 2020 (CalCCA Track 2 Proposal).

3 *California Community Choice Association Petition for Modification of D.19-06-026*, Oct. 30, 2019 (CalCCA PfM).

4 D.19-06-026 at 18.

5 Consistent with this approach, the Administrative Law Judge in R.17-09-020 issued a proposed decision (PD) on CalCCA's Petition on July 30, 2020. The Commission declined the Petition on grounds that the Commission had addressed the issue in D.20-06-031 and, therefore, the issue was moot. In other words, the PD leaves the issue to R.19-11-009 for resolution.

6 *See* D.20-06-041 at 64.

supply and demand dynamics that necessitate further exploration."[7] Calpine had more specific objections, arguing that CalCCA's proposal to use the terms "commercially reasonable price" and "commercially reasonable actions" left the proposal "unacceptably vague."[8] The Commission agreed that "there remain 'significant, unresolved issues that require further consideration before allowing such waivers, including potential leaning by LSEs and market power issues."[9] It concluded, as it did in D.19-06-026, "that a system and flexible waiver process requires further development and study."

To address these criticisms and to address the unresolved issues identified in in D.19-06-026 and D.20-06-031, CalCCA proposes that the issue be pursued in Track 3.B.

B. CalCCA Proposes a Study Process to Support Consideration of a System and Flexible RA Waiver

The Track 2 decision identified areas of concern that would need to be examined to allow for consideration of a system and flexible RA waiver. D.19-06-026 and comments on CalCCA's proposal suggest the need for greater clarity and certainty around market power and leaning concerns. In essence, the Commission needs to be assured that (1) a load-serving entity seeking a waiver took reasonable action to procure the needed system and flexible RA, and (2) its failure to procure these requirements arose from an exercise of market power. CalCCA proposes a process to be undertaken by a Working Group (WG) to study the system-level market dynamics that substantiate the proposed waiver.

As an initial step, WG participants, in coordination with the California Independent System Operator's (CAISO's) Department of Market Monitoring, would determine and compare supply and demand for 2019-2023. Demand could be forecasted based on actual monthly LSE

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7 *Ibid*.

8 *See* D.20-06-041 at 64-65.

9 *Id.* at 65.

obligations for 2019-2020, projected out for 2021-2023. Supply could be assessed by identifying capacity available in the market for use as system and flexible RA relying on the CAISO's annual publication of NQC and effective flexible capacity (EFC). Actual RA imports counted as system for 2019-2020 and the capacity available from pseudo-tied and dynamically scheduled import resources for 2021-2023 would be added to the CAISO system NQC total. For any such resources that were not included by the October 30 compliance deadlines, the study would investigate whether and when such resources were actually offered to the market. Without such an investigation, the study could identify generally that there is "sufficient capacity available in the system" but make no meaningful determination as to whether market power is being exercised. Additional potential areas of study could include system and flexible RA price trajectories or broader regional and market trends that could have material impacts on supply and demand, such as tightening of WECC-wide RA resources. The study would initially be presented in draft form, with a workshop to provide further input or propose modifications.

Once the WG had drawn conclusions from the study, parties could present informal proposals to address the study's findings. If conditions presented in the study suggest the RA market is vulnerable to the exercise of market power, workshops could be held to create waiver procedures that could be employed when:

- For future years, expected demand exceeds supply; or
- For past years, demand has exceeded supply that has been made available to the market before a specified pre-compliance date.

The proposals would need to identify more specifically the showings that would be required to obtain a waiver. For example, as Calpine suggests, it could be necessary to develop a "threshold price" above which it appears market power is being exercised and a waiver should be granted. Input and review by Energy Division staff would be sought throughout the process to ensure the

WG addressed Staff and the Commission's issues related to moving forward with a waiver process.

CalCCA proposes implementing the WG be implemented not later than 4Q 2020, with the aim of implementing the process for the 2022 compliance year. If the study demonstrates necessary conditions for the waiver for 2019-2021, a retroactive waiver process could be established for these periods.

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

August 7, 2020

CALCCA
ADVANCING LOCAL ENERGY CHOICE

August 13, 2020

VIA ELECTRONIC MAIL

Mr. Ed Randolph
Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenues
San Francisco, CA 94102

**Re: California Community Choice Association
Opening Comments on Draft Resolution E-5059**

Dear Director Randolph:

In accordance with Rule 14.5 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure and the notice accompanying Draft Resolution E-5059 (Draft Resolution), the California Community Choice Association (CalCCA) provides these opening comments on the Draft Resolution.

SUMMARY

Draft Resolution E-5059 (Draft Resolution) addresses implementation of changes to the Investor Own Utilities (IOUs) tariffs for Reentry Fees and Financial Security Requirements (FSRs) required by California Public Utilities Code Section[1] 394.25(e) for Community Choice Aggregators (CCAs). The Draft Resolution would approve with modifications Pacific Gas and Electric (PG&E) Advice Letter 5354-E and 5354-E-A, Southern California Edison (SCE) Advice Letter 3840-E, and San Diego Gas and Electric (SDG&E) Advice Letter 3257-E implementing the requirements of Section 394.25(e) and the revised reentry fee rules adopted by the Commission in Decision (D.) 18-05-022.[2]

In so doing, the Draft Resolution would establish important limitations on the IOUs' proposed advice letters to better align them with state law and the Commission's requirements. CCAs are preparing to negotiate and submit their first FSRs under the new rules and tariff provisions. It is critical that the Draft Resolution articulates a process that affords sufficient time and clarity on key details so it can be feasibly implemented. CalCCA offers these recommendations:

[1] All subsequent Article or Section references are to the California Public Utilities Code.
[2] Draft Resolution at 1.

- Adopt the limitations on IOU proposals.

- Afford sufficient time to negotiate and approve the terms of FSRs including: (1) the same timeframe as Energy Service Providers (ESPs) to update the FSR every six months; (2) 90 days following approval of directed changes to IOU tariffs for initial FSRs; and (3) 90 days following underperformance by an issuer to replace the issuer.

- Establish a process that would allow a CCA to comply with its FSR obligation when a utility is refusing to consent to reasonable FSR terms.

- Clarify an order of the Commission is required to activate an FSR.

- Eliminate the reference to Rule 10 of the IOU tariffs (Customer Billing Dispute Resolution).

- Confirm that FSRs using an escrow account instrument do not require credit support provisions for the third-party financial institution.

- Clarify that utilities may track, but may not request administrative costs or a reentry fee that departs from D.18-05-022.

- Direct each IOU to file their tariff changes in a single Tier 2 Advice Letter.

- Clarify the use of the term "beneficiary" to eliminate any ambiguity around the creation of trusts or fiduciary duties.

- Find that reentry fees may not be collected from involuntarily returned CCA customers subject to public Section 394.25(e).

- Direct the utilities to avoid communicating with customers about speculative reentry fee liability as a result of participation in a CCA program.

Appendix A proposes textual modifications to the Draft Resolution. CalCCA supports a timely implementation Section 394.25(e) for CCAs and looks forward to continuing to address related issues in the anticipated proceeding on the Provider of Last Resort ("POLR").

COMMENTS

1. The Commission Should Adopt the Draft Resolution's Limitations on the IOU Proposals

CalCCA supports the Draft Resolution's direction for utilities to file advice letters to revise their respective CCA tariffs within 30 days of this resolution.[3] CalCCA is hopeful that subsequent utility advice letters will not require additional protests and encourages the utilities to coordinate

[3] Draft Resolution at 25, Ordering Paragraph (OP) 8.

with CalCCA in advance of filing. CalCCA's original protest suggested a collaborative process to work through issues with the utilities. CalCCA remains committed and open to discussions on the issues.

CalCCA strongly supports the Draft Resolution's intent to establish balanced rules that do not prejudice CCAs by: (1) prohibiting the IOUs from terminating CCA service;[4] (2) rejecting the IOUs' proposed definitions of involuntary return;[5] and (3) requiring that FSR terms be subject to mutual agreement of the parties.[6]

CalCCA also appreciates the Draft Resolution's clarifications that: (1) as the beneficiary of the FSR IOU should not hold the funds;[7] (2) the changes to Direct Access (DA) customer rules are outside the scope of D.18-05-022 and should be rejected; and (3) that the procurement component of the FSRs will only include six months of incremental procurement costs.

These clarifications and findings simplify the remaining issues to be addressed in order for the CCAs to timely implement Section 394.25(e) and should be approved by the Commission.

2. The Draft Resolution Appropriately Recognizes But Does Not Provide Sufficient Time for CCAs to Negotiate and Approve the Terms of the Financial Security Requirement Instruments

The Draft Resolution appropriately finds that "[t]he formation process of an FSR instrument should provide all parties the opportunity to reach mutually agreeable terms, including those related to the specific condition under which the FSR is activated."[8] CCAs are local government entities that have their own public approval processes. CCAs may be required to undertake competitive solicitations for the financial services that will be needed to comply with the reentry fee program. Depending on the governance of the specific CCA, and the size of the FSR, approval may require a vote of a CCA's Commission, Board of Directors, or a Committee thereof, in a public meeting under the Brown Act. These approval processes are required by law and can add 30-60 days to the negotiation process as compared to an ESP. CalCCA provides specific timeline recommendations below for three instances that need to be addressed in the Draft Resolution.

a. CCAs Should Have No Less Time to Provide the Semiannual Updated FSRs Than Under the Existing ESP Rules

CCAs should have the same timeframe for the semiannual updates to FSRs as do ESPs. This is consistent with D.18-05-022 in which the Commission adopted the "same approach"[9] for CCA updates to the FSR as for ESPs, including that the "security amount [] be recalculated twice each year, in November and May, by the tenth day of each month, and with any adjustments to the

[4] Draft Resolution at 25, OP 6.b.
[5] Draft Resolution at 24, OP 3.
[6] Draft Resolution at 23, Findings 5, 13; *Id.* at 24, OP 4.a.
[7] Draft Resolution at 19.
[8] Draft Resolution at 23, Finding 5.
[9] D.18-05-022 at 11.

security amount implemented on the following January 1 or July 1, respectively."[10] This proposed timeline would allow a CCA more than 50 days for its semiannual update to the FSR. The Commission should clarify that CCAs should have no less time to post the regularly updated FSR than ESPs under existing rules.

b. The Commission Should Allow CCAs at Least 90 Days from Tariffs Being Finalized to Post Their First FSRs with Third Parties

The Commission should not require CCAs to post their first FSR until the IOUs have finalized their tariffs revisions. The Draft Resolution provides "all parties the opportunity to reach mutually agreeable terms…."[11] However, it directs the CCAs to post their FSR instruments within 30 days of this resolution[12] while also directing the IOUs to revise their applicable tariffs through advice letters withing 30 days from the resolution.[13] The requirement for CCAs to post their FSRs before the relevant IOUs' tariffs are finalized is not feasible as those tariffs will dictate some of the terms. The Draft Resolution should be modified to reflect that the conditional event starting the clock for a CCA's FSR deadline is the approval of the relevant IOU advice letter.

The Commission should provide the CCAs 90 days to negotiate and post their first FSRs. While CCAs will comply with the ESP timeline for updating the semiannual FSR as discussed above and directed in D.18-05-022 (*i.e.* over 50 days), the Draft Resolution provides even less time to post the initial FSR (*i.e.* within 30 days). The initial postings will require more extensive negotiations to define their terms, which were a significant source of dispute in the underlying proceeding,[14] and some of which remain in dispute today.[15]

The Commission should not lose sight of the fact the FSRs have three parties: the CCA, the IOU, and the issuer. It will take more than 30 days for these three parties to the FSR to work through the FSR's terms. CCAs may need an additional 30-60 days to administer a competitive solicitation and bring the FSR terms to their Board of Directors for a vote. CalCCA expects these issues to be timely resolved in good faith among the parties to the FSR without further Commission intervention. However, this will only be possible if those parties have sufficient time to work through the issues to define the initial terms. The Draft Resolution should be modified to provide CCAs 90 days to post the first FSR after the IOU tariffs are finalized.

c. The Commission Must Provide CCAs Sufficient Time to Replace an Underperforming Issuer of the FSRs

The Draft Resolution appropriately provides that the terms of the FSRs must be mutually agreed upon by the CCA and the IOU.[16] The IOUs have proposed 10 business days in their advice

[10] D.18-05-022 at 10-11 (citing to D.13-01-021 at 25).
[11] Draft Resolution at 23, Finding 5.
[12] Draft Resolution at 25, OP 9.
[13] Draft Resolution at 25, OP 8.
[14] R.03-10-003.
[15] Draft Resolution at 12-14, 16.
[16] Draft Resolution at 23, Finding 5.

letters for a CCA to replace an issuer that has fallen below the IOUs' standards after the FSR was issued.[17] This timeframe is simply infeasible. Replacing an issuer may require a competitive solicitation and a vote of the CCA's Board of Directors, which could take 30-60 days.

For these reasons, the Commission should allow CCAs at least 90 days to replace underperforming FSR issuers. The replacement timelines will vary by the instrument with escrow accounts likely being the simplest, followed by letters of credit, and surety bonds being the most complex. The Commission should establish a timeframe that will work regardless of the instrument.

d. The Commission Must Provide CCAs the Opportunity to Comply if the IOU Withholds Its Assent to the Terms of an FSR

CCAs should have the option to file their FSR advice letter directly with the Commission to ensure compliance if the IOU unreasonably withholds its assent to the proposed FSR terms and conditions. CalCCA understands its members will enter into negotiations with the utilities in good faith to reach mutually acceptable FSR terms as directed in the Draft Resolution. The Draft Resolution, however, provides no process to address an impasse in FSR negotiations.

A utility withholding agreement to reasonable FSR terms and conditions should not be permitted to force CCA non-compliance, which is exactly what the Draft Resolution would permit. This unilateral action by the utility could inappropriately impair the interests of the CCA, including reputational and financial interests.

The Commission, therefore, should revise the Draft Resolution to allow a CCA to file its FSR advice letter without the IOU's agreement, if needed to avoid non-compliance. The Commission has directed CCAs to submit their FSR instruments through an advice letter.[18] The advice letter process would provide the IOUs with an opportunity to file a protest to raise their concerns with the Commission. This process would likely incentivize the IOUs and CCAs to negotiate in good faith and keep the FSR postings from getting mired in unnecessary negotiations.

3. The Commission Should Revise the Draft Resolution to Clarify Several Provisions in Order to Better Effectuate their Purpose

a. An Order of the Commission Should be Required to Activate an FSR

The Commission should clarify that an order of the Commission is required to activate an FSR. The Draft Resolution provides "that activation of the FSR should not be unilateral action by the IOU…"[19] Indeed, calling on an FSR instrument is a significant action that is only likely to occur if a CCA service is being voluntarily or involuntarily terminated, both of which require an order of the Commission.[20] However, the Draft Resolution only uses the term "CPUC approval" as required to activate an FSR. Technically, Commission "approval" could be provided through no

[17] Draft Resolution at 7.
[18] D.18-05-022 at 16, OP 16.
[19] Draft Resolution at 13.
[20] Draft Resolution at 23, Finding 14.

Commission action after 30 days from the filing of a Tier 1 Advice Letter.[21] While such a process is appropriate for a reporting obligation, it should not be used for the extraordinary step of disturbing a CCA's financial position by finding the CCA out of compliance with the IOU's tariff. The Draft Resolution should be clarified to indicate "CPUC approval" for activation of an FSR requires an order of the Commission.

b. Rule 10 is Neither Needed Nor Appropriate to Resolve Disputed Reentry Fees

The Commission should revise the Draft Resolution to delete footnote 12 or any references to the IOUs' Rule 10. The Draft Resolution only allows an IOU to withhold customer payments without a Commission order if the reentry fees are undisputed.[22] Footnote 12 indicates that "[d]isputed charges are subject to the IOU's Rule 10."[23]

Rule 10 is not needed to resolve disputed reentry fees, which are adequately addressed through existing processes. A reentry fee dispute can arise under two potential scenarios, each of which has an existing resolution process:

> (1) <u>The CCA disputes the accuracy of the reentry fee established under the methodology adopted in D.18-05-022</u>. A CCA's opportunity to dispute the accuracy of the reentry fee is in response to the semiannual utility advice letters updating the reentry fees and FSRs.[24] Once those advice letters are effective, the CCA must provide the Commission-approved reentry fee through an FSR. At present, no additional dispute resolution process is required.
>
> (2) <u>The utility demands reentry fees that are not based on the methodology approved in D.18-05-022</u>. Resolving this dispute would either require modifications to or adequate compliance with the existing methodology for calculating the reentry fee adopted in D.18-05-022.[25] Such a demand is not currently authorized under Commission rules. However, the utilities could pursue a new Commission decision to modify the methodology. In fact, the Draft Resolution itself expresses an intent to explore one possible scenario where this may occur and a CCA has also become insolvent.[26]

Rule 10 is intended for billing disputes between the IOU and a retail electricity customer.[27] Rule 10 contains no guidance on disputed amounts owed by one LSE to another. Rule 10 is simply inapplicable to the issue of disputed reentry fee amounts. Any references to Rule 10 should be removed from the Draft Resolution.

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[21] General Order 96-B.
[22] Draft Resolution at 17.
[23] Draft Resolution at 17, FN 12.
[24] D.18-05-022 at 10.
[25] D.18-05-022 at 3-7.
[26] Draft Resolution at 10.
[27] *See* PG&E Rule 10; SCE Rule 10; and SDG&E Rule 10.

c. The Commission Should Clarify that the FSRs Using an Escrow Account Do Not Require Credit Support Provisions for the Third-Party Financial Institution

The option to post cash in an escrow account to satisfy the FSR is likely to be the primary instrument used to by many CCAs to meet the FSR requirements. CalCCA estimates that, for the foreseeable future, prices for energy and resource adequacy will remain below the IOUs' rates such that the minimum FSR of $147,000 will be required at the outset and for quite some time thereafter. An FSR of this size is most economically satisfied through cash held in an escrow account. Thus CalCCA believes that most, if not all of its members, will utilize the escrow account instrument to post the required FSRs. The Commission should ensure that this critical option does not have any unnecessary constraints.

The Commission should clarify that the independent financial institution holding cash in an escrow account does not need to meet any credit support requirements. This clarification is intended to avoid protracted negotiations between the CCAs and IOUs following approval of the Draft Resolution.

The Draft Resolution appropriately provides that the terms of the FSRs must be mutually agreed upon by the parties.[28] The cash in the escrow account represents the assets that will be used to satisfy a call on the escrow instrument. Where a CCA has posted cash, there is no need for the IOU to further assure assets will be available through credit support arrangements. This is in contrast to the issuer of a letter of credit or surety bond; which should satisfy a set of credit support requirements because the issuer is making a commitment to use its own assets to satisfy a call on these instruments. In fact, the IOUs suggested a list of such criteria in their advice letters related to Security Deposits for letters of credit and surety bonds[29] but provided no such criteria for an escrow account. The Draft Resolution should be clarified to reflect that no credit be required when a cash escrow account is used as the FSR instrument.

d. The Commission Should Clarify that Utilities May Track, but May Not Request, Administrative Costs or a Reentry Fee that Departs from D.18-05-022

The Draft Resolution should be clarified to indicate that the IOUs must adhere to the Commission-approved methodologies for administrative costs. D.18-05-022 established the methodology for calculating the administrative costs of the reentry fee to use a proxy (*i.e.* the established per-customer fee for voluntary returns for each utility). The decision does not allow the IOUs to seek recovery for administrative expenses under any other methodology. It did not adopt the methodology proffered by PG&E and cited in the Draft Resolution.[30] However, Section 4 of the Draft Resolution, appears to indicate the IOU may use an alternative methodology "if the IOU believes the use of the proxy amount is insufficient…." This is also reflected in PG&E's proposed changes to its tariff:

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[28] Draft Resolution at 23, Finding 5.
[29] *See e.g.* PG&E 5354-E, Attachment 1: Rule 23 Revisions, Section V, W.
[30] Draft Resolution at 15, FN 9 (citing "Exhibit JU-01, July 28, 2017, at 35 (lines 29-34) (R.03-10-003)").

> using the proxy amount…, unless PG&E has tracked the actual incremental administrative costs of the Involuntary Return, in which case PG&E reserves the right to use the actual incremental administrative costs noting that utilities requested the right to seek recovery for administrative costs that differ from the proxy cost….[31]

PG&E's requests that were not adopted by the Commission are not an appropriate legal basis to depart from a Commission-approved methodology. CalCCA supports the Draft Resolution's direction that utilities should be able to track the actual costs associated with an actual involuntary return. This information could be useful to revise the methodology for calculating the FSR in the future and ensure bundled and unbundled customers are not inappropriately shifting costs. The Draft Resolution should be modified to make clear that utilities may only seek cost recovery under a Commission-approved methodology.

e. The IOUs Should File Their Proposed Tariff Changes in Response to the Draft Resolution in a Tier 2 Advice Letter

The Commission should direct the utilities to revise their tariffs in a single Tier 2 advice letter filing. The Draft Resolution appears to direct each of the utilities to make corrections to their Rule 23 or 27 tariffs through two separate advice letters, both filed within 30 days of the resolution. OP 4 directs the utilities to file a Tier 1 advice letter;[32] and OP 8 directs the IOUs to file a separate Tier 2 advice letter.[33] These separate advice letters will be filed at the same time, to make changes to the same tariffs, address the same subject matter, and will likely involve the same parties. The Commission should streamline the process and consolidate these changes by aligning OP 4 and OP 8 to both call for a Tier 2 advice letter. This way, each IOU will only have to file one advice letter to revise their tariffs.

f. The Commission Should Clarify that the Reentry Fee Rules or FSR Instruments Do Not Create a Trust Relationship or Fiduciary Duties

The Draft Resolution rightfully acknowledges that the IOU advice letters mischaracterize the relationship between IOUs and CCA programs in connection with FSRs and properly instructs the IOUs to "refile all relevant tariff sheets to reflect the new IOU rule as *beneficiary* of the CCA FSR and remove reference to the FSR being posted with the IOU."[34] While CalCCA agrees with the analysis and supports the approach contained in the Draft Resolution, the use of the term "beneficiary" is ambiguous.

[31] PG&E 5354-E Rule 23, Sheet 62, Section W.3.a.1.
[32] At 24, OP 4.
[33] At 25, OP 8.
[34] Draft Resolution at 19 (emphasis added).

The term is used in one sense as the Draft Resolution intends, i.e., a person "who is designated to receive the advantages from an action or change; esp., one designated to benefit from an appointment, disposition, or assignment (as in a will, insurance policy, etc.), or to receive something as a result of a legal arrangement or instrument."[35] However, the term is also used in a different sense to mean a person "to whom another is in a fiduciary relation, whether the relation is one of agency, guardianship, or trust; esp., a person for whose benefit property is held in trust."[36] While Section 394.25(e) and D.18-05-022 require CCA programs to be responsible for reentry fees in the event of an involuntary return of customers, these authorities do not purport to, and cannot be interpreted to, create a legal trust between IOUs and CCA programs, or establish any fiduciary duties. The Commission should resolve the ambiguity by replacing the term "beneficiary" with the term "recipient", or otherwise clarifying that the Commission does not interpret the governing legal authorities to create a trust relationship or fiduciary duties.

4. The Commission Must Clarify that Reentry Fees May Not Be Collected from Involuntarily Returned CCA Customers Subject to Public Utilities Code Section 394.25(e)

a. Section 394.25(e) Prohibits the Commission from Collecting Reentry Fees from Involuntarily Returned Customers

The final resolution should include a finding that recites or otherwise directly references the language contained in Section 394.25(e) that expressly prohibits reentry fees from being collected directly from involuntarily returned CCA customers. The statute provides:[37]

> If a customer of an electric service provider or a community choice aggregator is involuntarily returned to service provided by an electrical corporation, any reentry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electrical corporation *shall be the obligation of the electric service provider or a community choice aggregator,* except in the case of a customer returned due to default in payment or other contractual obligations or because the customer's contract has expired. As a condition of its registration, an electric service provider or a community choice aggregator shall post a bond or demonstrate insurance sufficient to cover those reentry fees. *In the event that an electric service provider becomes insolvent and is unable to discharge its obligation to pay reentry fees, the fees shall be allocated to the returning customers.*

While CalCCA agrees with the Draft Resolution that under Section 394.25(e) "CCAs bear the cost responsibility regardless of whether the costs of returning customers are in excess of the FSR,"[38] the plain language of the statute establishes a general rule that reentry fees must be recovered directly from a CCA program rather than CCA customers returning to bundled service

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[35] Black's Law Dictionary (10th ed. 2014) p. 186.
[36] Black's Law Dictionary (10th ed. 2014) p. 186.
[37] Section 394.25(e) (emphasis added).
[38] Draft Resolution at 10.

on an involuntary basis. Had the Legislature intended reentry fees to be recoverable from CCA customers, it would have said so, and included language in the statute creating an exception to the general rule, as it did for DA customers.

Section 394.25(e) establishes rules for DA customers in the event that an ESP becomes insolvent and is unable to pay reentry fees. In that circumstance, the statute provides that "the fees shall be allocated to the returning customers." The rules of statutory interpretation dictate that where legislation expressly includes one class of entity but not another, the exclusion is intended to be purposeful unless a contrary legislative intent is expressed elsewhere in the statute or is otherwise compelled.[39] No similar language creating an exception and allowing for the recovery of reentry fees from CCA customers exists in the statute, and the absence of such language must be interpreted to reflect the intent of the Legislature that CCA customers pay no such fees. The Legislature has provided sufficient guidance, and absent new legislation, the Commission must follow the language of the statute. By establishing a general rule that reentry fees be recovered from CCA programs and ESPs, and creating a limited exception for customers of an insolvent ESP, the Legislature has provided its directive that CCA customers not be held responsible—a directive the Commission must follow.

b. The POLR Statute Did Not Change the Commission's Authority Under Section 394.25(e)

The Draft Resolution rejects the IOUs' proposal to have involuntarily returned CCA customers bear responsibility for uncollected reentry fees and directs that issue for further consideration to the POLR rulemaking.[40] CalCCA supports this exploration under the new POLR bill (SB 520 (2019)). Indeed, the FSR posted under Section 394.25(e) is relevant to that statute because it provides collateral support to the utility for a function that is analogous to the POLR function (*i.e.* serving involuntarily returned customers). However, SB 520 is distinct from Code Section 394.25(e).

The Legislature passed SB 520 long after D.18-05-022 was adopted and the IOU advice letters implementing it were filed. The issues raised therein were in the public record and could have been expressly addressed by the Legislature, but they were not. The POLR statute amends Section 216 and adds Article 8.5, Section 387 but makes no changes or references to Section 394.25(e). While Sections 216 and 387 may provide the Commission authority to develop new cost recovery mechanisms, Section 394.25(e) still provides the Commission no statutory authority to assign reentry costs directly to involuntarily returned CCA customers. The Commission should modify OP 5 to make this explicit and provide clarity as to the effect of Code Section 394.25(e).

5. The Commission Should Direct the Utilities to Avoid Communicating with Customers About Speculative Reentry Fee Liabilities

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[39] *See, e.g., Dyna-Med, Inc. v. Fair Employment & Housing Com.* (1987) 43 Cal.3d 1379, 1391 (describing a rule of statutory interpretation *Expressio unius est exclusio alterius* – the expression of one thing implies the exclusion of others). *See also Esberg v. Union Oil Co*. (2002) 28 Cal.4th 262, 269 (where statutory language is "unambiguous" a court need not consider "extrinsic aids" to determine its meaning).

[40] At 24, OP 5.

As discussed above, the Commission does not have authority under Section 394.25(e) to impose reentry fees on involuntarily returned CCA customers. However, even if the Draft Resolution is not explicit about this point, the final resolution should provide explicit direction to the utilities to avoid communicating to customers about the speculative risk that reentry or similar fees may be imposed directly on customers. If customer liability is not be settled by the Commission's final resolution, there is a real possibility that customer communications on the subject may lead to confusion and may even be prohibited by D.12-12-036. The potential for misleading communications regarding the specter of customer liabilities may deter customers from joining a CCA program or encourage them to voluntarily leave a CCA program. To prevent confusing or misleading communications, the final resolution should direct the utilities to refrain from any customer communications about the possibility that CCA customers may be directly assessed reentry fees from an involuntary return.

CONCLUSION

CalCCA appreciates the Commission's thoughtful and careful consideration of these comments on the reentry fee obligations and associated FSRs. As described above, CalCCA supports the limitations on the utilities' proposals and offers important clarifications and considerations to establish a successful reentry fee program. CalCCA recommends the Draft Resolution be modified prior to adoption as described above. CalCCA also supports a timely implementation Section 394.25(e) for CCAs and looks forward to continuing to address related issues in the anticipated proceeding on the Provider of Last Resort.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl

Evelyn Kahl
General Counsel

cc via email:
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Service Lists for R.03-10-003

APPENDIX A

Findings

16. The posting of the FSR refers to the demonstration of the financial instrument having been formed, and the IOU made its obligee, ~~beneficiary~~ recipient, or equivalent.

18. CCAs may file their FSR advice letters to ensure compliance where the utility is withholding assent to the terms.

19. Reentry fees may not be collected directly from involuntarily returned CCA customers subject to public Section 394.25(e).

Ordering Paragraphs

4. “The IOUs shall refile their tariff sheets via Tier ~~1~~2 advice letter to clarify the following:…”

5. The recovery of reentry fees from involuntarily returned customers in the event that the CCA is unable to recover the fees is prohibited by Section 394.25(e), however this issue shall be ~~deferred to~~ reexamined in the POLR proceeding.

9. ~~All~~ Each CCA~~s~~ shall post a financial security instrument within ~~30 days of this resolution~~ 90 days of the disposition of their utility’s advice letter for tariff changes directed in this Resolution. Semiannual FSRs will be updated using the same timeline as the ESP rules as directed in D.18-05-022. CCAs will replace underperforming issuers of FSRs within 90 days of the default.

10. Utilities shall not communicate with customers about direct reentry fee liability as a result of participation in a CCA program.

Changes to Discussion

“D.18-05-~~015~~022 found that accurately predicting the timing and manner of a mass involuntary return of CCA customers to IOU service is not feasible.” Draft Resolution at 12.

“The IOUs should resubmit tariffs to clarify that activation of the FSR requires an order of the CPUC for approval, this change should be made through a Tier ~~1~~2 AL.” Draft Resolution at 13.

“With the exception of issues 1, 9 and, 10, we find that the IOUs’ replies reasonably addressed CalCCA’s protests. We do clarify that for issue 3, no credit support provisions will be required beyond cash posted for escrow accounts.” Draft Resolution at 16.

“~~Disputed charges are subject to the IOU's Rule 10.~~” Draft Resolution at 17, Footnote 12.

"In the event that an involuntary return is triggered, and fees are incurred, the utility shall file a Tier 1 AL to create a memorandum account to track the actual costs of returning customers and launching the involuntary return process. The utilities will continue to request administrative and procurement costs from CCAs consistent with the methodology adopted in D.18-05-022 until the Commission directs otherwise." Draft Resolution at 17.

"…Tier ~~1~~2…" Draft Resolution at 2, 13, and 17.

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

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	)))))	Rulemaking 19-09-009 (Filed September 19, 2019)

**OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS
ON TRACK 2 PROPOSALS**

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August 14, 2020

On Behalf Of:
Peninsula Clean Energy Authority
Sonoma Clean Power Authority
Redwood Coast Energy Authority
San Jose Clean Energy
Pioneer Community Energy
California Choice Energy Authority
Monterey Bay Community Power
San Diego Community Power
East Bay Community Energy
Marin Clean Energy

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	)))))	Rulemaking 19-09-009 (Filed September 19, 2019)

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON TRACK 2 PROPOSALS

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the July 23, 2020 *Administrative Law Judge's Ruling Requesting Comment on Track 2 Microgrid and Resiliency Strategies Staff Proposal, Facilitating the Commercialization of Microgrids Pursuant to Senate Bill 1339* (the "Ruling"), the Joint CCAs[1] hereby submit the following opening comments on the Track 2 Staff Proposal ("Staff Proposal") provided as Attachment 1 to the Ruling. In these opening comments, the Joint CCAs offer both general comments and responses to the questions set forth in the Ruling.

I. INTRODUCTION

The Joint CCAs are encouraged by the Energy Division's latest round of proposals, as set forth in the Staff Proposal, and the Energy Division's identification and discussion of the novel issues that microgrids raise in the Concept Paper.[2] The Joint CCAs appreciate the hard work and dedication reflected in the Staff Proposal and Concept Paper, and thank the Energy Division for

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1 The Joint CCAs consist of the following Community Choice Aggregation ("CCA") programs: Peninsula Clean Energy Authority ("PCE"); Sonoma Clean Power Authority ("SCP"); Redwood Coast Energy Authority ("RCEA"); San Jose Clean Energy ("SJCE"); Pioneer Community Energy ("Pioneer"); the California Choice Energy Authority ("CalChoice"); Monterey Bay Community Power ("MBCP"); San Diego Community Power ("SDCP"); East Bay Community Energy ("EBCE"); and Marin Clean Energy ("MCE").

2 Ruling, Attachment 2, *Microgrids and Resiliency Staff Concept Paper*.

its efforts thus far. The Staff Proposal, with the clarifications and refinements recommended below, represents a significant step towards meeting the requirements of Senate Bill ("SB") 1339, while the Concept Paper lays the groundwork for addressing the remaining critical issues that must be resolved in order to "facilitate the commercialization of microgrids" as required by SB 1339: 1) developing a general microgrids tariff that covers the full range of microgrid types; and 2) further streamlining and standardizing the interconnection process for microgrids. As set forth in detail below, the Commission should take advantage of its current momentum, party focus, and the groundwork laid in the Staff Concept Paper to address these issues as part of, or in parallel to, the work being done in Track 2, with the goal of resolving all critical commercialization issues by the statutory deadline.

II. GENERAL COMMENTS

A. The Commission Must Develop a General Microgrid Tariff

SB 1339 requires that the Commission take actions by December 1, 2020 to facilitate the commercialization of microgrids and reduce barriers to microgrid deployment.[3] In the Concept Paper, the Energy Division recognizes that "commercialization" is the introduction of a new product to the general market, and that in this case the microgrid itself is the product being marketed.[4] The Joint CCAs strongly support the Energy Division's definition. Critically, this definition recognizes the importance of creating a general market – a market that allows open competition by a variety of microgrid models, including microgrids that are owned, developed, and/or operated by non-IOU third parties. This is consistent with the SB 1339 commercialization guidance, which identifies the legislature's intended end-product of the work

[3] Pub. Util. Code Section 8371. All further statutory references are to the California Public Utilities Code unless otherwise noted.

[4] Concept Paper at 15-16.

being done in this docket – microgrids that are "a successful, cost-effective, safe, and reliable commercial product that helps California meet its future energy goals and provides end-use electricity customers new ways to manage their individual energy needs."[5]

The lack of a general microgrid tariff is the single greatest remaining barrier to achieving the commercialization of microgrids and the open and competitive microgrid marketplace required by SB 1339. Unlike the relatively narrow tariffs recommended in the Staff Proposal, which focus on a customer-sited, customer-facing tariff only, a general microgrid tariff would cover all likely microgrid configurations, and would include both general rules and principles for microgrids and specific subtariffs for customer-sited, customer-facing microgrids covering a single parcel or adjacent parcels and utility-sited microgrids that serve multiple parcels/customers. A general microgrid tariff and related subtariffs should clearly specify roles and responsibilities of each party to the tariff: distribution utility, load serving entity or entities, microgrid operator, and end-user. The tariff should also specify the financial relationship between the distribution utility and the microgrid project so that necessary distribution upgrades are performed in a timely, efficient fashion at known cost. The absence of such a tariff, or suite of tariffs, creates a high degree of cost uncertainty for both third-party developers seeking to market microgrids and parties like CCAs that are seeking to implement their own microgrids.

In order to remove this barrier and facilitate the development of an open and functional microgrid market, the Joint CCAs request that the Commission explicitly include the development of a utility-sited microgrid subtariff in proposal 3 (which already addresses the

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[5] SB 1339, Legislative finding (e) ("The Public Utilities Commission, Independent System Operator, and State Energy Resources Conservation and Development Commission must take action to help transition the microgrid from its current status as a promising emerging technology solution to a successful, cost-effective, safe, and reliable commercial product that helps California meet its future energy goals and provides end-use electricity customers new ways to manage their individual energy needs").

development of a general customer-sited microgrid tariff). While the Joint CCAs acknowledge that a utility-sited microgrid tariff will likely not be fully fleshed out in detail before the statutory deadline, we strongly recommend that stakeholders at least initiate this process under Track 2 of the Proceeding and develop "conceptual cornerstones" of a future utility-sited microgrid tariff proposal. The process to develop such a proposal could proceed as follows:

- Each IOU would be required to submit a proposed *framework* for a utility-sited microgrids tariff to the docket within 30 days of a ruling by the assigned ALJ.
- All interested parties would also have the opportunity to submit their own utility-sited tariff proposals at the same time.
- The Energy Division would then schedule 2-3 workshops to discuss and elaborate on the tariff proposals and to attempt to build consensus tariff proposals to be developed further and then submitted to the Commission for approval.
- After the workshop process, parties would formally submit either their consensus proposals or their individual proposals to the Commission.
- Proposals would then be addressed through a round of formal comments, with the aim of building a robust record to allow the Commission to issue a Decision adopting, at a minimum, a conceptual framework for a utility-sited microgrid tariff by the statutory deadline.

While this is an aggressive timeline, the CCAs believe that it is entirely feasible for parties to develop robust tariffs for Commission adoption by the end of 2020. While staff has already proposed the development of a customer-facing, customer-sited general microgrid tariff in proposal 3, the Joint CCAs urge the Commission to also begin the development of a general microgrid for utility-sited microgrids now. Such efforts would not occur in a vacuum. Significant work on utility-sited microgrid tariffs has already been done by a number of parties. For instance, RCEA and PG&E have engaged in robust tariff discussions related to the Redwood Coast Airport Microgrid. These discussions have resulted in the identification of numerous technology and operational considerations that are directly applicable to the development of a general utility-sited microgrid tariff. Using these principles as a starting point will help structure the general utility-sited microgrid tariff development efforts and will give these efforts a significant head start.

III. COMMENTS ON THE STAFF PROPOSAL

A. Comments on Proposal 1 – Direct the utilities to revise Rule 2 to explicitly allow the installation of microgrids as special facilities

<u>Question P1-1</u>:

> *In response to Proposal 1 to direct the utilities to revise Rule 2 to explicitly allow the installation of microgrids as special facilities, please indicate support or opposition to Option 1, Option 2, or Option 3 and explain your support or opposition.*

<u>Question P1-2</u>:

> *In response to the Staff Proposal's recommendation, should the Commission adopt Option 2? If not, what modifications should the Commission consider?*

<u>Response to Questions P1-1 and P1-2</u>:

The Joint CCAs support Proposal 1, Option 2 with modification. Subject to the modifications discussed below, Option 2 appears to be a reasonable path forward to better enabling the use of Rule 2 as one of many available "tools" to support installation of microgrids.

Question P1-4:

Is there anything more the Commission should consider about revising Rule 2 to allow the installation of microgrids as added/special facilities? Should the Commission consider alternative approach to ease barriers to the development of added/special facility microgrids?

Response to Questions P1-4:

The Joint CCAs support Proposal 1, Option 2 with two modifications. First, Proposal 1, Option 2 should be clarified to unambiguously state that Rule 2 special facilities are just one of many available approaches to microgrid development. Proposal 1, Option 2 applies to only a narrow subset of microgrids – those that are customer-sited and where the microgrid owner desires to deed to the utility the microgrid controller and authorize the IOU to operate the controller. While Proposal 1 will assist in the development of microgrids of this type by allowing utilities to forego the need for explicit authorization from the Commission, Proposal 1 should not stand in lieu of developing a suite of tariffs necessary to allow for full commercialization of microgrids, and should not be treated as a "default" or "required" pathway to microgrid deployment.

Third, consistent with its statutory obligation to remove barriers to microgrid development, as part of the implementation of Proposal 1, Option 2, the Commission should require a review and update of the IOUs' Rule 2 financing and O&M rates for special facilities to ensure that these rates are reasonable and do not impose a financial barrier to microgrid deployment.

B. Comments on Proposal 2 – Direct the utilities to revise Rule 18/19 to allow microgrids to serve critical customers on adjacent parcels.

Question P2-1:

In response to Proposal 2 to revise PG&E Rule 18, SCE Rule 18 and SDG&E Rule 19, please indicate support or opposition to Option 1, Option 2, or Option 3 and explain your support or opposition.

Response to Question P2-1:

The Joint CCAs support the adoption of Proposal 2, Option 1 and request that Option 1 be modified to fully support the commercialization of microgrids by eliminating Option 1's language limiting eligibility to critical facilities owned by municipal corporations. As proposed, Option 1 would take a narrowly limited step towards the commercialization of what is likely to be one of the more common types of microgrid – customer-sited, customer-facing, grid-tied microgrids that take power from the grid as normal during blue-sky conditions, but during outages allow one premise to provide power to a second, adjacent premise. To ensure that the microgrid only operates during outage conditions, Options 1 and 2 would require that the operator install a device preventing parallel operation of the service line between the premises during normal operations.

Options 1, 2, and 3 include unnecessary restrictions that prevent the effective commercialization of this type of microgrid. Options 1 and 2 would limit eligibility to critical facilities (as defined by D.19-05-042) that are owned by "municipal corporations" and only allow electricity service to adjacent premises to conduct emergency and/or critical operations. This opening is too narrow as it does not allow the full range of microgrid configurations currently allowed by Section 218. Under Section 218(b)(2), a regulated "electrical corporation" *does not* include a corporation or person producing power solely for:

> The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated or on real property immediately adjacent thereto, unless there is an intervening public street constituting the boundary between the real property on which the electricity is generated and the immediately adjacent property and one or more of the following applies:
>
> A. The real property on which the electricity is generated and the immediately adjacent real property is not under common ownership or control, or that common ownership or control was gained solely for

purposes of sale of the electricity so generated and not for other business purposes.

B. The useful thermal output of the facility generating the electricity is not used on the immediately adjacent property for petroleum production or refining.

C. The electricity furnished to the immediately adjacent property is not utilized by a subsidiary or affiliate of the corporation or person generating the electricity.

Thus, Option 1 needlessly constrains microgrid deployments configured in a manner that complies with Section 218, as Section 218 does not limit microgrid eligibility to critical facilities, and does not limit microgrid operation to municipal corporations.

Option 2 includes the same restrictions as Option 1 but adds a "subscription limit" that would allow only 10 microgrid projects to be deployed under this exemption statewide. This subscription limit is an unnecessary barrier to the development of the microgrids allowed by Section 218 and would hamper urgent efforts to improve resiliency through microgrid deployment. Option 3, maintaining the status quo, is incompatible with the Commission's statutory mandate to remove obstacles to the commercialization of microgrids.

Instead of any of these options, the Joint CCAs support reforming the IOUs' Rule 18/19 to clearly allow microgrids to be formed up to the limits imposed by Section 218. Namely, a microgrid of any size could be formed if the following two conditions are met: 1) the power is used to serve the customer or tenants of the customer; and 2) the microgrid is formed to serve two or less other customers or corporations on adjacent parcels without an intervening street. Provision of service during a grid down event should also not be a constraining requirement as it is not a limit found in Section 218.

Given the legislative determination that these limited expansions of private electrical service are allowed, it does not appear that any public interest is served by limiting eligibility to microgrid in the ways described under Options 1 or 2. The Proposal states that the purpose of Rule 18/19 is to ensure the safety and reliability of the electricity provided from the distribution grid to the customers, and to protect customers who may have little to no choice regarding their electricity source. The Joint CCAs, as load serving entities, are sympathetic to these concerns, but the legislature has made determinations that certain limited private provision of electrical service is reasonable. This determination should be respected and the IOU rules reformed to allow the formation of microgrids in configurations up to the full extent of current law. Such flexibility will support the deployment of microgrids at critical facilities and in other contexts where the economics work for energy users.

The Joint CCAs further note that the Option 1 and Option 2 limitations are problematically narrow even for the implementation of critical facility resiliency microgrids. A range of entities other than municipal corporations operate critical facilities and infrastructure. This includes government entities like town and county governments, tribal governments, state and federal agencies, and joint powers authorities (including some water districts, ports, and CCAs). Any reasoning for making municipal corporations eligible for Proposal 2 microgrids should extend equally to these entities. Non-governmental entities also operate critical facilities and infrastructure. Critically, this includes nonprofits and business entities that operate hospitals and other medical facilities. It is not clear that any interest is served by denying such critical facilities eligibility for Proposal 2 microgrids, and if any such interest does exist, it is clearly outweighed by the health and safety interests served by ensuring that critical facilities are able to continue operation during outages.

Question P2-2:

In response to the Staff Proposal's recommendation, should the Commission adopt Option 2? If not, what modifications should the Commission consider?

Response to Question P2-2:

The Joint CCAs strongly oppose Option 2, which would retain the restrictions included in Option 1 while adding a subscription limit of 10 microgrid projects in total for all IOU service areas. In light of the operational and definitional limitations of Proposal 2 microgrids and the fact that the Legislature, in Section 218, has already explicitly authorized the deployment of these microgrids, such a subscription limit is unlikely to protect or further any identifiable public interest. To the contrary, the subscription limit would unnecessarily delay or prevent the deployment of Proposal 2 microgrids, frustrating the Commission's fulfillment of its guiding mandates in this proceeding – facilitating the commercialization of microgrids and protecting the public health and safety through improved outage resiliency. The Commission should be taking steps to encourage, not limit, the widespread deployment of Proposal 2 microgrids, as these microgrids will increase resiliency even if installed at sites other than municipally owned critical facilities.

As set forth above, the Commission should adopt a modified version of Option 1 that eliminates ownership and facility type requirements and modifies Rule 18/19 to allow all microgrid types authorized by Section 218.

Question P2-8:

Critical information facilities are included in the list the IOUs are required to develop and maintain pursuant to D.19-05-042. Are there other critical facilities or facilities that should be considered but are not part of D.19-05-042's list? Please justify your response.

Response to Question P2-8:

If the Commission decides to limit Proposal 2 to critical facilities, the definition of critical facilities should use the most current definition of critical facilities and infrastructure ("CFI") adopted in the Commission's De-Energization Rulemaking. The Staff Proposal cites the definition of CFI from the De-Energization Phase 1 Decision, D.19-05-042. However, the Commission expanded and updated this definition in the De-Energization Phase 2 Decision, D.20-05-051. Of note, D.20-05-051 expands the definition of CFI to include:

- Public safety answering points (including 911 call centers);
- Transportation facilities and infrastructure including facilities associated with automobile, rail, aviation, major public transportation, and maritime transportation for civilian and military purposes.[6]

Any CFI eligibility requirement should be based on the Commission's full definition of CFI, not the narrower list of facilities listed in an older Decision.

C. Comments on Proposal 3 – Direct the utilities to develop a microgrids rate schedule

Question P3-1:

> *In response to Proposal 3 to develop a standardized rate schedule for combinations of technologies that are eligible for interconnection under Rule 21 and together comprise a microgrid, please indicate support of or opposition to Option 1, Option 2, Option 3, Option 4, and/or Option 5. Explain your support or opposition.*

Response to Question P3-1:

Proposal 3 would require that the IOUs develop a rate schedule for a single subtype of microgrids – customer-sited, customer-facing microgrids. This is only a small subset of the statutory definition of "Microgrids" established in SB 1339, and as such does not, in itself,

[6] D.20-05-051, Appendix A at 10.

satisfy the Commission's statutory obligation to facilitate the development of microgrids by reducing barriers to microgrid deployment. Tariffs for customer-sited, customer facing microgrids should be developed as part of a holistic effort to develop a general microgrid tariff with specific subtariffs for customer-facing and grid-facing microgrids, as proposed above, not as a separate carve-out.

If despite these concerns the Commission decides to pursue Proposal 3 as a separate effort, the Joint CCAs request that the Proposal 3 tariff be developed in accordance with the following principles:

- The tariff should be technology agnostic, but should not allow financial support for fossil-fueled backup generation.
- Microgrids that meet the requirements set forth in Tables 3-3 and 3-4 of the staff proposal should be exempt from part or all of the Cost Responsibility Surcharge as discussed in those Tables. However, microgrids are prevented from being exempted from certain non-bypassable charges, such as public purpose program charges, by statute. This nuance will need to be addressed.
- "Critical facilities" referenced in Table 3-3 should be expanded to include all CFI identified in D.20-05-051.
- CCAs should have the option to wave standby generation charges for microgrids in their service territory as CCAs have exclusive ability to set their rates and may want to absorb standby generation charges as a means to facilitate microgrids in their communities.

D. Comments on Proposal 4 – Direct the utilities to develop a microgrids pilot program

Question P4-1:

In response to Proposal 4 to direct the utilities to develop a microgrid pilot program, please indicate support or opposition to each of the options. Explain your support or opposition.

Response to Question P4-1:

The Joint CCAs do not support Proposal 4, as currently structured, but believe that a significantly modified version of the Proposal may be viable. The Joint CCAs' primary concern with Proposal 4 is the fact that it provides funding for additional microgrid pilot programs. "Pilot programs" by definition, are small-scale programs intended to test the feasibility of, and gather information regarding, cutting-edge technologies or practices. Limited microgrid deployment through additional pilot programs will not solve the resiliency challenges posed by the current state of the grid, and pilot programs are unlikely to provide new lessons or insights beyond those already available. Microgrids have already been the subject of numerous pilot programs. In California, the California Energy Commission has used over $101 million in public funds to support 45 microgrid pilot projects.[7] These efforts have proven very fruitful, and continued investment in one-off pilot programs will likely produce diminishing returns. Microgrids are now technologically and operationally mature, and, as SB 1339 recognizes, are ready for large-scale commercialization. The primary remaining barriers to this widespread commercialization are regulatory – most importantly the lack of a comprehensive microgrid tariff. Any further pilot programs will only provide resiliency solutions limited to the area of

[7] California Energy Commission Presentation "Lessons Learned from CEC EPIC Microgrid Research Activities (July 7, 2020) at Slide 4, available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=233760

their deployment. The Commission should embrace full commercialization of microgrids via the tariff development described above.

If the Commission decides to pursue Proposal 4, it should modify the Proposal by eliminating the "pilot program" language, instead creating a general program to provide financial support for resiliency microgrids. However, the Commission should recognize that the most effective ways for it to encourage microgrid deployment are by adopting a general microgrids tariff and implementing the CRS exemptions recommended in Proposal 4 for all microgrid types (not just customer-sited, customer-facing microgrids). These steps should be the Commission's first priority, and a modified Proposal 4 should be adopted as a way to build on and support these primary reforms. Such a program should take a consistent approach similar to PG&E's CMEP implemented by all three IOUs. In considering this program, the Commission should look for ways to build on and improve the work already done by PG&E in its CMEP.

Additionally, we take note of the discussion in the concept paper about the opportunity for coupling microgrid deployments with the Distribution Investment Deferral Framework and Competitive Solicitation Framework. The Joint CCAs support a close coordination between these efforts and the development of IOU programs to support and streamline microgrid deployments so that any deferral opportunities are made transparent to communities and developers as they consider microgrid deployments. Done properly, the distribution deferral value of microgrids could provide cost-saving benefits to all distribution customers which further addresses concerns over cost shifts as the grid is modernized. We look forward to delving into this topic further in this docket.

Question P4-2:

> *Should the Commission adopt Staff's recommended options? If not, what modifications to Staff's recommended options should the Commission consider?*

Response to Question P4-2:

The Joint CCAs believe that Staff's recommendation that each project's costs be recovered from ratepayers in the same county where the project is located is problematic. First, this recommendation represents a significant departure from standard cost allocation practices, under which costs for capital projects and operations and maintenance ("O&M") are allocated among PG&E's rate classes as a whole on a systemwide basis, even if a particular project or investment only benefits ratepayers in a specific region. The Joint CCAs strongly recommend that the Commission not deviate from this established methodology in this instance, and that the Commission carefully think through the broad ratesetting implications of county-specific cost allocation. All counties face man-made and natural disasters that make grid resilience efforts a priority, so it makes sense to broadly socialize the costs of these efforts. Moreover, resilience in one county has benefits to adjacent counties and the state in providing shelter as populations migrate to avoid danger and because they can conserve out of county resources through their own resilience. These benefits strongly militate against a county-level cost allocation.

Second, this recommendation would impose an unreasonable burden on the vulnerable ratepayers that Proposal 4 purports to protect. This is particularly true for projects located in lower income, less populated, rural counties. In such counties, project costs would be split among a smaller number of ratepayers, leading to a higher per-ratepayer impact. In low-income counties, this impact would be borne by a higher proportion of vulnerable low-income ratepayers. The Commission should not penalize vulnerable ratepayers for taking advantage of programs intended to give their communities much needed resiliency improvements. In many cases, vulnerable counties suffer from lower reliability and higher wildfire risk due to IOU underinvestment in T&D system maintenance, upgrades, safety operations like brush clearing.

Neither these counties' citizens nor their local governments have influence over IOU investment and operations, and a county's ratepayers should not be penalized for deploying microgrids needed to mitigate the impact of IOU reliability problems.

Third, the Joint CCAs question the recommendation's practicality. Tracking individual project costs, allocating costs on a per-county basis, and imposing county-specific rates (with associated billing system changes) would likely require significant work by the utilities, including major accounting, IT, and billing system changes. These costs are not justified.

E. Comments on Proposal 5 – Direct the utilities to conduct pilot studies of low cost reliable electrical isolation methods

Question P5-1:

> *In response to Proposal 5 to direct the utilities to conduct pilot studies of low cost reliable electrical isolation methods, please indicate support or opposition to Option 1 or Option 2. Explain your support or opposition.*

Response to Question P5-1:

The Joint CCAs support Proposal 5, Option 1 subject to modification. As a general matter, it makes sense to require that the IOUs study ways to use their existing installed smart-meters for electrical isolation. However, this should not be a "pilot" study. It should be a comprehensive study that provides concrete guidelines and conclusions for the widespread, real-world use of the remote shut-off capability of each IOUs smart meters for microgrid islanding and potential use as a tool to mitigate the impacts of public safety power shutoff events. The IOUs should be required to provide specific, concrete conclusions and guidance regarding:

- The islanding capability of the specific models of smart meters installed on the IOUs system;
- Specific identification of any utility-side IT or distribution hardware upgrades needed to enable the use of smart meters for islanding;

- A proposal for allowing microgrids installed, owned, and/or operated by third parties to take advantage of the IOUs' smart meters' islanding capability.

IV. CONCLUSION

The Joint CCAs thank the Commission for their consideration of the matters discussed herein.

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Respectfully submitted,

/s/David Peffer

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Sonoma Clean Power Authority
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San Jose Clean Energy
Pioneer Community Energy
California Choice Energy Authority
San Diego Community Power
Monterey Bay Community Power
East Bay Community Energy
Marin Clean Energy

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	Rulemaking 18-12-006 (Filed Dec. 19, 2018)

COMMENTS OF THE JOINT CCAS ON SECTIONS 6, 11.1, AND 11.2 OF THE DRAFT TRANSPORTATION ELECTRIFICATION FRAMEWORK

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On behalf of Peninsula Clean Energy Authority, Redwood Coast Energy Authority, East Bay Community Energy, the City of San José, Marin Clean Energy, Silicon Valley Clean Energy, and Sonoma Clean Power

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COMMENTS OF THE JOINT CCAS ON SECTIONS 6, 11.1, AND 11.2 OF THE DRAFT TRANSPORTATION ELECTRIFICATION FRAMEWORK

I. Introduction & Summary

In response to the Administrative Law Judge's Ruling Adding Staff Proposal for a Draft Transportation Electrification Framework to the Record and Inviting Party Comments dated February 3, 2020, the E-Mail Ruling Denying Joint Motion to Stay Proceeding and Resetting Procedural Schedule dated March 24, 2020, and the Email Ruling Resetting Procedural Schedule for Comments on Transportation Electrification Framework dated August 4, 2020, Peninsula Clean Energy Authority ("PCE"), Redwood Coast Energy Authority ("RCEA"), East Bay Community Energy ("EBCE"), the City of San José, Marin Clean Energy ("MCE"), Silicon Valley Clean Energy ("SVCE"), and Sonoma Clean Power ("SCP") (collectively, the "Joint CCAs")[1] submit these Comments on Sections 6, 11.1, and 11.2 of the February 3, 2020 Draft of the Transportation Electrification Framework ("Draft TEF").

The Joint CCAs largely support the Energy Division's suggested frameworks in the areas of equity, vehicle grid integration ("VGI"), and marketing, education, and outreach ("ME&O") and appreciate the Energy Division's emphasis on ensuring that the state's transportation electrification ("TE") efforts prioritize these areas of focus. The Joint CCAs firmly believe that allowing community choice aggregators ("CCAs") to serve as TE program administrators alongside investor-owned utilities ("IOUs") will be critical to the overall success of the state's efforts to provide equitable access to TE investments and to achieve broad VGI deployment.

[1] Each of the Joint CCAs has authorized PCE to file these comments on their behalf. Note that the group of CCAs that comprises the Joint CCAs, as defined in this filing, is not identical to the group of CCAs that has filed under this designation in prior filings in this docket.

II. Draft TEF Section 6 – Equity

A. Section 6, General Comments: To Ensure that the State's TE Framework Adequately Addresses Equity Issues, CCAs Must Have an Active Role in Advancing TE Programs.

As the Draft TEF recognizes, "[t]he transformation of the transportation sector will require deep engagement with communities, particularly those who have been historically underserved."[2] The Joint CCAs agree with the Energy Division that, through their TE programs and efforts, all load-serving entities ("LSEs") need to ensure that they are appropriately prioritizing communities that have a history of unfair treatment and disproportionate impacts from environmental hazards, economic burdens, or both.[3] In addition, the Joint CCAs support the Energy Division's focus on the ESJ Action Plan, Tribal Consultation Policy, and Low-Income Barriers Study highlighted in the Draft TEF as resources that provide a solid foundation from which to begin outlining guidance on TE equity for program administrators.[4] The Energy Division's suggested framework, which is informed by these resources, regarding how program administrators should address key equity barriers like consumer awareness and community engagement provides a helpful starting point to guide program administrators' planning efforts.[5]

To effectively address these equity-related barriers identified by the Energy Division, program administrators must take concrete steps to ensure that underserved communities play a primary and critical role in the development of TE plans ("TEPs") so that their needs are not secondary to other statewide goals. In addition, as discussed further in Section II.B herein, programs coming out of these TEPs need to reflect the realities and constraints that these local communities face, and with attention to this local context, work toward meaningful progress to address these constraints and ensure that all ratepayers have an opportunity to benefit from TE programs.

As local, community-governed public agencies, CCAs are able to quickly and effectively identify and respond to the unique needs of the community members they serve, including those

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[2] R.18-12-006, *Administrative Law Judge's Ruling Adding Staff Proposal for a Draft Transportation Electrification Framework to the Record and Inviting Party Comments, Transportation Electrification Framework Energy Division Staff Proposal*, p. 60 (February 3, 2020) ("Draft TEF").
[3] *Id*., pp. 60-61.
[4] *Id*., pp. 64-65.
[5] *Id*., pp. 66-68.

of underserved communities. In contrast with traditional IOU programs, CCA programs are designed with an understanding of specific community needs and opportunities in mind and leverage local partnerships to ensure efficient and effective delivery. CCAs also regularly engage with their local communities through citizens advisory committees and local outreach, and therefore will be adept at incorporating these communities into their TEP processes and planning efforts.

For all these reasons, and others that the Joint CCAs will address in more detail in their filings on Section 10 of the Draft TEF, the Commission should revise the Draft TEF to allow CCAs to serve as program administrators alongside utilities. In line with this recommendation, the Joint CCAs recommend that Section 6 of the Draft TEF be revised to contemplate that CCAs will also be serving as program administrators, and that the same frameworks and guidelines to be applied to IOU program administrators in the context of equity issues will also be applied to CCA program administrators.

1. CCAs Have a Demonstrated Ability to Design Programs to Serve ESJ Communities.

CCA administration of TE programs will serve equity goals identified in the Draft TEF. CCAs already offer a robust set of TE programs specifically designed to serve the environmental and social justice ("ESJ") communities in their service territories, in the areas of electric vehicle ("EV") rebates, e-bike rebates, programs geared to help low-income renters, and community grants providing broader support for local communities, more generally. CCAs will be able to increase and scale these efforts if permitted to serve as program administrators alongside IOUs.

For instance, in the area of EV rebates for low-income customers, PCE has partnered with Peninsula Family Service[6]—a highly respected locally headquartered social services organization with deep local roots—to offer its Drive Forward Electric program, which provides a rebate of up to $4,000 on used EVs to residents with low to moderate incomes, as well as vehicle loans and financial education to help applicants.[7] PCE also helps residents qualify for additional rebates, such as those offered by the Bay Area Air Quality Management District and the California Vehicle Rebate Project ("CVRP"). The City of San José has built on the success of PCE's Drive Forward Electric Program and has also partnered with Peninsula Family Service to provide used EV

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[6] *See About Us*, Peninsula Family Service, https://www.peninsulafamilyservice.org/about-us/.
[7] *Affordable Used Electric Cars*, Peninsula Clean Energy, https://www.peninsulacleanenergy.com/driveforwardelectric/.

assistance and financial education to low and moderate income residents in San José.[8] MCE's MCEv Vehicle Rebate program offers a $3,500 rebate on new EVs for income-qualified residents and, similar to PCE's program, helps residents qualify for additional rebates from other sources such as the CVRP, for a combined incentive of up to $8,000.[9] PCE also offers, through its E-bike Rebate, a first of its kind program to provide e-bike rebates exclusively to residents with low incomes. The program, recently approved by the PCE Board of Directors in July 2020, will provide a rebate of up to $800 to qualifying residents and will be set up to be utilized as a point-of-sale discount at local bike shops, or as a post-sale rebate for online purchases. The program also partners with the Silicon Valley Bicycle Coalition for community outreach and promotion.[10]

CCAs are also adept at designing programs to serve low-income renters, and at ensuring local context informs program design so that these programs provide logical, cost-effective solutions. For instance, through PCE's MUD Low Power Pilot, PCE is working to address the relative shortage of EV charging options available to the underserved residents of multi-unit dwellings ("MUDs"), utilizing Level 1 charging as a scalable low-cost charging solution that provides for driver needs of 40 to 50 miles of charge overnight, well in excess of average daily driving needs, while avoiding expensive and often prohibitive service upgrades. This program reflects PCE's familiarity with the existing housing stock in San Mateo County, where over 80 percent of the housing stock is made up of MUDs that are over 50 years old and that have limited electrical capacity.[11] PCE projects typical Level 1 circuit installation costs for retrofits will be approximately $2,000 per port without service upgrades. Level 1 charging is therefore a key element of a portfolio of solutions (including Level 1, energy-managed Level 2, and Fast Charge) to achieve scaled deployment of charging—such as 20 plus ports per site—where all residents

[8] *Drive Forward EV Financial Assistance Program with the City of San Jos*é, Peninsula Family Service, https://www.peninsulafamilyservice.org/financial-assistance-program/; *Financial Assistance*, San José Clean Energy, https://sanjosecleanenergy.org/drive-electric/#financing.
[9] *Electric Vehicle Rebates and Rates*, MCE, https://www.mcecleanenergy.org/ev-drivers/#EVrebate.
[10] *Regular Meeting of the Board of Directors of PCEA*, Peninsula Clean Energy (July 23, 2020), https://www.peninsulacleanenergy.com/wp-content/uploads/2020/07/2020-07-23-PCE-Board-Agenda-Packet-2.pdf.
[11] *San Mateo County Apartment Building Analysis*, p. 9, Peninsula Clean Energy (October 24, 2018), https://www.peninsulacleanenergy.com/wp-content/uploads/2020/08/PCE-Multifamily-Building-Characterization-2018.pdf.

have access to charging.[12] Further, this pilot is also testing various Level 1 "smart outlets," which meet MUD operator requests such as access control and billing functionality.

Additionally, Level 1 and energy-managed Level 2 EV charging stations are also a significant component of PCE's building code enhancements for local governments, which provide for 100 percent of residential units to have fully EV-ready parking. Level 1 and energy-managed Level 2 EV charging stations are also a substantial part of PCE's EV Ready charging incentive and technical assistance program, which has a goal of installing 3,500 charge ports in San Mateo County over the next four years, including about 1,400 ports specifically for MUDs (about 40 percent of total ports installed).

While it may not be readily apparent to all stakeholders in the TE community that additional investments like these in Level 1 charging are needed,[13] PCE has developed this understanding and these programs based on its connections to and work with low-income members of our local communities. This engagement has demonstrated to PCE that Level 1 charging should be an integral part of its residential-based charging strategy, and that generally, charging solutions should not be approached with a one-size fits all mindset. Rather, the Commission should allow local context to inform program administrators' approaches to charging solutions, ensuring that funding can be made available to support a range of options, including both Level 1 and Level 2 chargers.

EBCE also has advanced substantial efforts to help low-income renters. For instance, it incorporated a local MUD assessment into its pending 2021 CALeVIP project, utilizing a cluster analysis of MUDs to inform a reserved portion of incentive funds for direct current fast charging

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[12] *See generally The Infrastructure Needs and Costs for 5 Million Light-Duty Electric Vehicles in California by 2030*, CalETC (June 1, 2020) (discussing costs of scaled deployment, including Level 1 deployment scenarios).

[13] *See, e.g.*, R.18-12-006, *Chargepoint, Inc. Reply Comments on Staff Proposal for Draft Transportation Electrification Framework (Sections 7 and 8)*, pp. 7-8 (August 7, 2020). ChargePoint argues that the TEF should not "promote" Level 1 charging on the basis of the "minimal" cost differential between Level 1 and Level 2 chargers, and suggests that Level 1 charging stations do not have the functionalities that would enable them to meaningfully contribute to VGI efforts, which can be used to reduce costs. Further, ChargePoint argues that due to this "limited functionality[,]" the TEF should not encourage investment in Level 1 chargers in MUDs and DACs. As discussed further in Sections II.B and III.B herein, the cost differential between Level 1 and Level 2 chargers is significant, and investing in Level 1 chargers is not contrary to VGI goals, as these chargers can also offer managed charging and curtailment functionalities. In addition, as demonstrated by PCE's MUD Low Power Pilot, Level 1 chargers can offer low-cost charging solutions responsive to the housing stock within a community, which in some cases is unable to support investments in Level 2 chargers.

("DCFC") projects near these clusters. Further, this analysis also informed the California Energy Commission's ("CEC") support for allowing affordable MUDs located outside of traditional disadvantaged community ("DAC")/low-income community ("LIC") boundaries to be eligible for enhanced incentives, ensuring these incentives actually reach the local communities that need them most. SVCE, similarly, has identified clusters of MUD residents that could benefit from nearby DCFC and is offering incentives of $10,000 per charger on top of CALeVIP incentives for selected sites that are in or near these clusters.[14] The City of San José, as part of its 2020 CALeVIP project, is requiring at least 25 percent of total CALeVIP incentives for Level 2 and DCFC projects to be invested in either DACs or LICs.[15]

Finally, CCAs have a broader demonstrated commitment to ESJ communities, which spans efforts within the TE space as well as other efforts to promote clean energy and greenhouse gas reductions within these communities. As one example, PCE has awarded grants of $75,000 each for six local pilot projects to support innovative ideas on how to reduce greenhouse gas emissions and provide community benefits as part of its Community Pilot Program. One of these projects was the Build it Green – Healthy Homes Connect Pilot, which is providing home repairs to low-income residents in East Palo Alto and Daly City. In addition to reducing indoor air pollution and safety risks, these upgrades are intended to help these homes meet minimum compliance requirements to qualify for additional energy efficiency upgrades or free solar from existing energy assistance programs.[16] Similarly, via PCE Community Outreach Small Grants, PCE is partnering with local community non-profits to help provide outreach to the diverse communities within San Mateo County and promote clean energy and PCE programs.[17]

MCE has also been offering a variety of clean energy programs to low-income and DAC customers over the past several years. Most notably, MCE has been administering its Low-Income Families and Tenants ("LIFT") pilot under the umbrella of the IOU's Energy Savings Assistance ("ESA") program since 2015. Under the LIFT pilot program, MCE offers home safety, comfort

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[14] *Incentives for EV Fast Charging Near Multifamily Housing*, Silicon Valley Clean Energy, https://www.svcleanenergy.org/dcfastchargers/.
[15] *Charging Incentives*, *Project Guidelines*, San José Clean Energy, https://sanjosecleanenergy.org/ev/#evcharging.
[16] *Community Pilot Awardees*, Peninsula Clean Energy, https://www.peninsulacleanenergy.com/community-pilots/.
[17] *Community Outreach Small Grants*, Peninsula Clean Energy, https://www.peninsulacleanenergy.com/small-grants/.

and energy savings measures, including the installation of heat pumps, to low-income customers in multifamily properties.[18] Furthermore, MCE's low-income solar program complements California's low-income solar programs with additional incentives. Finally, MCE launched its Energy Storage Program in July 2020, offering performance-based incentives to install customer-sited energy storage systems for both residential customers and critical facilities. MCE's Energy Storage Program gives priority to residential customers and critical facilities that are (or serve) low-income and disadvantaged customers, those who have a medical need, and those who live in areas most likely to be threatened by wildfires and utility public safety power shutoffs ("PSPS").[19]

Importantly, given that CCAs have this close relationship with the ESJ communities in their service territory, they are always aligned with the objective of serving those local communities. IOUs do not always have the same incentives. For instance, RCEA has low-income regions within its service territory, but Pacific Gas and Electric Company ("PG&E") has yet to deploy any EV Charge Network ("EVCN") electric vehicle supply equipment ("EVSE") installations in the entire region, as shown in the EVCN project map.[20] This may be due to the generally high costs associated with deploying projects within the territory, or other incentive structures that ultimately result in this program's inability to serve these low-income customers. As a result, RCEA customers pay for this program without accessing corresponding benefits from this funding. Allowing CCAs to serve as program administrators would address existing equity issues by ensuring that CCAs, like RCEA, could administer programs to serve ESJ communities within their service territories that are currently left behind by utility programs. CCAs' incentives are aligned with providing programs to these overlooked communities, consistent with the standard equity approach: focusing on societal value through greater access, rather than economic value driven by profitability and shareholder return.

Allowing CCAs to serve as program administrators will also have broader local workforce development benefits. As CCAs provide programs to their local communities, they inherently develop local TE expertise around design, project management, construction, service, and

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[18] *Energy Savings for Multifamily Properties*, MCE, https://www.mcecleanenergy.org/multifamily-savings/.
[19] *Energy Resilience*, MCE, https://www.mcecleanenergy.org/resiliency/.
[20] *EV Charge Network Resources, EV Charge Network Map*, PG&E, *available at* https://www.pge.com/en_US/large-business/solar-and-vehicles/clean-vehicles/ev-charge-network/program-participants/resources.page.

inventory. CCAs also provide continuity beyond sales and construction of any one initiative. This local emphasis establishes a trained and engaged workforce and supply network for ongoing operations and maintenance and future build-outs.[21] This is essential for isolated communities where large implementation providers and their subcontractors are typically located hours away.

2. CCAs Have a Demonstrated Ability to Respond Quickly to the Immediate Needs of ESJ Communities.

CCAs are also nimble organizations that are able to quickly adapt to changing circumstances—whether related to local conditions and challenges, technology innovations, or otherwise—to the benefit of communities in need. In addition to the broad programmatic efforts addressing long-term needs discussed above, CCAs have also quickly developed COVID-19 response programming, swiftly responding to a crisis that is disproportionally impacting minority communities and the medically vulnerable. For example, EBCE suspended bill collection and implemented flexible payment plans. And, as of August 2020, EBCE had launched a corporate match program for donations and committed to contributing over $1,000,000 to the relief efforts of the communities they serve. CCAs are committed to fostering intentional relationships with community-based organizations leading grassroots-level organizing and support efforts that meet the community where they are at. To that end, EBCE has also approved $70,000 in grants to support local food programs and over $300,000 in grants to nearly 50 different community-based organizations serving residents and businesses in EBCE's service area most impacted by COVID-19. There are also 20 organizations that are in the approval process for an additional $200,000 in grants from EBCE.[22] MCE also suspended bill collection and compiled energy affordability resources to support their customers during the pandemic.[23] PCE acted very quickly to help its

[21] For example, MCE's Solar One project "supported 341 jobs and maximized local economic benefits through the City of Richmond's 50 percent local workforce hiring requirement, in which Richmond-based contractors, suppliers and union labor were employed. MCE partnered with RichmondBUILD, which has successfully graduated hundreds of students and placed an impressive 80 percent of its graduates into well-paying jobs, to train and hire skilled, local graduates for the project. In addition, approximately $1.8M was spent on project materials purchased or rented in Contra Costa County, further supporting the local economy." Such local workforce development and the use of local workforce in CCA-sponsored programs also has significant equity benefits as well. *See MCE Solar One Ribbon Cutting*, MCE, https://www.mcecleanenergy.org/news/press-releases/mce-solar-one-thinking-globally-building-locally/.

[22] *How Bay Area "Community Choice" Energy Programs Are Supporting Us During COVID-19*, Sierra Club San Francisco Bay, https://www.sierraclub.org/san-francisco-bay/blog/2020/04/how-bay-area-community-choice-energy-programs-are-supporting-us.

[23] *Id.*

low-income residents by allocating $3.6 million toward bill relief for 36,000 customers covered under the California Alternative Rates for Energy or Family Electric Rate Assistance rate plans, providing a $100 bill credit in April and May of 2020.[24]

In addition to COVID-response programming, CCAs have also acted quickly in response to the growing threat of PSPS events, launching efforts to help underserved communities access power during these events. For example, through its Power on Peninsula Program, PCE has partnered with Senior Coastsiders,[25] a local community-based organization, to provide free portable backup batteries during PSPS events to medically vulnerable residents who depend on reliable power for their medical equipment.[26] As another example, RCEA operates two EV charging stations within the Blue Lake Rancheria microgrid that stayed online during PG&E's recent October 2019 PSPS event, and delivered 57 kWh to EVs, at no cost to users, during the outage.[27] Finally, shortly after PSPS events last fall affected hundreds of thousands of customers in the Bay Area, EBCE, PCE, and SVCE issued a joint solicitation to install up to roughly 20 MW of solar and battery backup power on homes throughout their service areas, including 6,000 households vulnerable to emergency power shutoffs during the wildfire season.[28] These examples demonstrate how CCAs are generally quick to respond to local concerns and emergencies with localized solutions, due in part to their close connections to the communities they serve.

3. CCAs Are Generally Sensitive to Affordability in Their Program Design.

In addition to this expertise in designing programs to serve ESJ communities, CCAs are also generally sensitive to affordability in their program design. In addition to PCE's MUD Low Power Pilot and EV Ready program discussed above, MCE's MCEv Charging Program is another example of how CCAs are expert at providing cost-effective TE solutions. This program has, as of the end of July 2020, resulted in 150 Level 2 network ports installed across 21 sites at

[24] *Id.*
[25] *See Senior Coastsiders*, https://www.seniorcoastsiders.org.
[26] *You May Qualify for Free Portable Backup Batteries for Medical Needs*, Peninsula Clean Energy, https://www.peninsulacleanenergy.com/pop-medical/.
[27] *North Coast Plug-In Electric Vehicle Readiness Plan Implementation: Phase 2*, p. 28, California Energy Commission Clean Transportation Program (November 2019).
[28] *Press Release, Bay Area Community Energy Agencies Reach Emission-Free Power Resiliency Agreements*, Peninsula Clean Energy (July 30, 2020), https://www.peninsulacleanenergy.com/bay-area-community-energy-agencies-reachemission-freepower-resiliency-agreements/.

$4,708/port,[29] while PG&E's EVCN port costs are estimated at approximately $18,000/port.[30] The demonstrated ability of CCAs to deploy TE solutions in a relatively cost-effective manner will allow any program funds allocated to CCAs' TE efforts to go farther and, thereby, reach more communities in need of EV charging infrastructure.

CCAs' demonstrated ability to design TE programs to serve ESJ communities equitably, quickly, and at lower cost than current administrators provides powerful support for CCA administration of TE programs. Accordingly, the Draft TEF should be revised to make clear that CCAs are permitted to apply to administer TE programs. Further, the Commission should also revise Section 6 of the Draft TEF to contemplate this structure.

B. Section 6, Stakeholder Question 1: Localized Program Design is an Additional Requirement for Success that Should be Considered to Adequately Address Equity Within Program Administrators' TE Programs.

As the Energy Division recognized in its discussion of equity issues in the Draft TEF, "each community is unique and thus may have unique needs and barriers based on geographic, economic, demographic, or cultural factors."[31] The Joint CCAs agree, and urge the Commission to revise the Draft TEF to recognize an additional significant equity-related requirement[32] that program administrators must address in their TEPs and program design efforts: localized program design. As the Energy Division has recognized, each community is unique, so to be successful EV programs must be designed with local context in mind to address needs and barriers based on

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[29] Personal Communication with MCE, August 19, 2020 (note that this cost data is from an MCE internal program report). These numbers represent project costs as of July 28, 2020. According to MCE, these per port costs include hardware, installation (including as needed electric upgrades and parking lot re-striping/bollards), and the first year of networking fees. These project costs are not inclusive of customer or MCE staff time, warranty fees, and permit fees. MCE has kept its per project costs low since 81 percent of its projects completed to-date are 2-6 ports and thus distribution level upgrades are rarely needed. Of those 17 projects, only 1 required electrical system upgrades. Also, ADA costs are lower with smaller projects since most of MCE's customers have an additional ADA spot that can be converted to EV accessible spots, whereas larger EV charging projects require more than one EV accessible spot and thus incur those associated costs.

[30] PG&E EV Charge Network Quarterly Report (July 1, 2019 – September 30, 2019), p. 13, *available at* https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/PGE-EVCN-Quarterly-Report-Q3-2019.pdf (reflecting PG&E's average cost per port of $17,973 through Q3 2019 in the EVCN program).

[31] Draft TEF, p. 65.

[32] Note that the Joint CCAs refer to this as an "equity-related requirement" throughout these comments. In the terms laid out in the Draft TEF, this should be considered an additional equity-related "barrier", along with the seven barriers already recognized in the Draft TEF. *See id*., p. 66.

geographic, economic, demographic, or cultural factors.[33] Localized program design that focuses on these barriers is vitally important to the development of TEPs and programs that address underserved communities in practice, rather than just in theory.

The statewide suite of TEPs and associated TE programs should be varied in their design to meet the wide range of needs within the communities across program administrators' service territories. Localized program design—achieved in part through the leveraging of connections to local organizations as well as through community outreach and input—is essential to ensuring that TE programs are not out of touch with the constraints, opportunities, and goals of the communities they intend to serve.

Further, attempting to identify and define underserved communities on a macro level, without also allowing for the flexibility for program administrators to supplement these designations to account for local context when necessary, would potentially lead to equity goals and programs that do not reflect individual communities. To allow for this flexibility, program administrators' TEPs should identify underserved communities in their service territories, utilizing the range of equity designations proposed in the Draft TEF as well as any proposed and well-supported additional designations necessary to more accurately describe underserved communities in these service territories.[34] TEPs should then address the strategies that the program administrator will implement to ensure TE investments are directed to address the needs of these ESJ communities as well as the key equity barriers identified by the Energy Division. If localized program design were adopted as an additional equity-related requirement, then each TEP would also address the program administrator's strategy for ensuring these TE investments account for local context—both local constraints and opportunities.

Making program administrators plan their investments with local context in mind will improve overall program efficacy. For instance, only through its local MUD assessment, described above, was EBCE able to understand the ecosystem of multifamily properties in Alameda County and assess where DCFC projects should be sited to best serve underserved MUD residents within its service territory. Similarly, only by understanding the charging needs and constraints of MUD residents in San Mateo County, as well as the housing stock in the County, could PCE effectively

[33] *Id*., p. 66.
[34] *Id*., p. 71. Note the Draft TEF highlights that program administrators should ensure their programs are geared not only to DAC as defined statewide, but also, to other ESJ communities falling outside the statewide DAC definition.

design a program like its MUD Low Power Pilot, through which PCE plans to install between 14 and 20 outlets with smart plug technology at a projected cost of between $2,000 and $4,000 per port (including "all-in" two-year network and warranty fees and some panel upgrades), to provide residents with low-cost charging solutions. As a point of comparison, PG&E's EVCN program has an average cost of nearly $18,000 per port installed.[35] As these numbers indicate, and as further demonstrated by the California Electric Transportation Coalition's June 2020 study,[36] the cost differential between Level 1 and Level 2 charging is not "minimal", as some TE stakeholders suggest,[37] and is not limited to the differential in hardware costs alone.[38] Indeed, by avoiding new energy service or upgraded equipment such as panels and transformers, Level 1 projects can save thousands of dollars in costs, especially as projects scale to significantly more ports per site.

Along the same vein, only by coordinating with local community-based organizations can program administrators learn how to best engage with their local communities and promote programs to serve them. PCE's E-bike Rebate program, for instance, partners with the Silicon Valley Bicycle Coalition for community outreach and promotion,[39] the City of San José's Drive Electric Financial Assistance Program provides EV and financial empowerment workshops through a partnership with Peninsula Family Service,[40] and EBCE is partnering with California Interfaith Power & Light to collaborate with local faith-based groups on developing a plan to deploy publicly accessible EV charging stations at congregations throughout Alameda County. As demonstrated by these examples, CCAs are inherently skilled at designing programs informed by

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[35] PG&E EV Charge Network Quarterly Report (July 1, 2019 – September 30, 2019), p. 13, *available at* https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/PGE-EVCN-Quarterly-Report-Q3-2019.pdf (reflecting PG&E's average cost per port of $17,973 through Q3 2019 in the EVCN program).

[36] *The Infrastructure Needs and Costs for 5 Million Light-Duty Electric Vehicles in California by 2030*, p. 7, Table 5, CalETC (June 1, 2020), *available at* https://caletc.com/just-released-infrastructure-needs-assessment-for-5m-light-duty-vehicles-in-california-by-2030/ (providing the cost advantages of Level 1 vs. Level 2/DCFC in terms of customer make-ready costs, and showing that Level 1 chargers range in cost from $125 to $175, while Level 2 range from $500 to $2,500, and DCFC range from $20,000 to $100,000) ("CalETC Study").

[37] R.18-12-006, *Chargepoint, Inc. Reply Comments on Staff Proposal for Draft Transportation Electrification Framework (Sections 7 and 8)*, pp. 7-8 (August 7, 2020).

[38] *See, e.g.*, CalETC Study, p. 6, Table 4 (illustrating that this cost advantage is compounded by the lower likelihood of a lower-power Level 1 charger triggering the need for a utility upgrade).

[39] *Regular Meeting of the Board of Directors of PCEA*, Peninsula Clean Energy (July 23, 2020), https://www.peninsulacleanenergy.com/wp-content/uploads/2020/07/2020-07-23-PCE-Board-Agenda-Packet-2.pdf.

[40] *Financial Assistance*, San José Clean Energy, https://sanjosecleanenergy.org/drive-electric/#financing.

local context and by input from our community advisory committees and local community groups. These efforts stem directly from the fact that CCAs are community-governed, local public agencies with an inherent community focus and close connections to their local communities.

An understanding of local context is also vitally important in program design, in part, to allow program administrators to target TE investments such that those investments have the greatest impact on ESJ communities—recognizing that not all investments need to be made *within* ESJ communities to have a significant impact on ESJ communities. For example, when medium/heavy-duty ("MD/HD") EVSE investments are made in the Tri-Valley area of Dublin, Livermore, and Pleasanton—which are not DAC/LIC designated areas—that directly benefits residents in the communities neighboring the Port of Oakland ("Port"). In order for urban delivery and MD/HD goods movement drivers to transition to EVs, charging solutions must not only be sited at trucking company facilities throughout the Bay Area and the Port; common charging yards must also be publicly available and strategically sited to enable en route fleet charging. This infrastructure is also critically needed to support the trucks moving goods from the Central Valley and beyond, to the Port and other Bay Area markets.

CCAs are well-positioned to collaborate to support this transition by working together to understand fleet origins and destinations across CCA service areas, and by using this information to invest in optimal siting of EVSE to benefit our most vulnerable communities. This kind of local planning will be vital to realizing the benefits of electrifying the MD/HD goods movement sector. As the Draft TEF notes, given that "DACs are often disproportionately affected by air pollution from transport, transit, and freight, the focus on the MD/HD sector is critical to addressing not only TE infrastructure barriers, but also equity and environmental justice."[41]

For all these reasons, the Draft TEF should recognize how important local context is in designing effective TE programs, especially those that address equity-related goals. The Draft TEF should therefore be revised to add localized program design as an additional equity-related requirement that program administrators must address in their TEPs and program design efforts, and to recognize CCAs' inherent strengths in localized program design.

[41] Draft TEF, p. 63.

C. <u>Section 6, Stakeholder Question 3</u>: If the Final TEF Adopts Specific Definitions of DAC, Low-Income, and Medium-Income, Program Administrators Should Also be Permitted to Present Alternative Definitions that Better Reflect the Communities in Their Service Territories.

The Joint CCAs support the list of equity designations proposed in the Draft TEF, as well as the Energy Division's position that program administrators should ensure their programs are geared not only to DAC as defined statewide, but also, to other ESJ communities falling outside the statewide DAC definition.[42] Further, the Joint CCAs believe that, to reflect the variation across program administrators' service territories, administrators should be permitted to propose additional designations in their TEPs, supported by data, that better describe underserved communities in their service territories. For example, San Mateo County's Community Vulnerability Index[43] utilizes seven different indicators of vulnerability drawn from the United State Census Bureau's American Community Survey to illustrate the overlap of these indicators and help guide the allocation of San Mateo County's resources to better serve residents in need.[44]

Along the same lines, if specific statewide definitions of DAC, low-income, and medium-income are adopted, a program administrator should also be allowed to present alternative definitions in their TEPs, supported by data, that better reflect the communities within their service territories.

Allowing this flexibility in terms of identifying and defining underserved communities within each service territory would ensure that programs are designed to reflect the demographics and needs of each distinct service territory. In each case, any supplemental and/or alternative definitions would be presented in TEPs, supported by data, and subject to Commission review.

III. <u>Draft TEF Section 11.1 – VGI</u>

The Joint CCAs appreciate the Energy Division's recognition of the importance of VGI to the state's overall TE goals, and agree that it is critical that program administrators' TE efforts work to ensure that incremental load from increasing numbers of EVs in the state is integrated in

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[42] *Id*., p. 71.
[43] *Community Vulnerability Index*, County of San Mateo, https://cmo.smcgov.org/cvi.
[44] As another example, a program administrator may want to propose in its TEP that, given a significant community of residents within its service territory that have a Pollution Burden score (as defined by CalEnviroScreen) in the top 15th percentile, these "pollution burdened communities" should be recognized with a unique equity designation within the service territory. If this proposal is well supported by data and a demonstrated need within the service territory, the Commission may want to use its discretion to allow that program administrator to explicitly design programs geared to serve that designated community. *See CalEnviroScreen 3.0*, pp. 103-04, CalEPA (January 2017).

a way that provides grid benefits.[45] The Joint CCAs also appreciate the Energy Division's recognition that CCAs have a role to play in advancing VGI.[46] In fact, as LSEs with clean power portfolios, CCAs are in a prime position to maximize the benefits of EVs through VGI, aligning charging demand with renewable supply, reducing air pollution in our communities, and enhancing grid reliability. CCAs have engaged in and contributed to the Commission's Interagency VGI Working Group, are actively piloting various VGI solutions, and have fully implemented successful VGI programs. In light of these ongoing efforts, CCAs stand ready to increase and scale these VGI programs as TE program administrators.

A. <u>Section 11.1, Stakeholder Question 2</u>: Existing Activities Such as the Interagency Vehicle Grid Integration Working Group Will Provide Sufficient Output and Identifiable Next Steps to Specifically Target VGI Activities.

CCAs have been actively involved in shaping the recommendations flowing from recent working groups centered on VGI. In particular, PCE and EBCE were both active participants in the Commission's Joint Agency VGI Working Group and are committed to continue to work through stakeholder processes like this to advance VGI use cases and policies for their customers. In addition, CCAs like PCE have been engaged not only in the Joint Agency VGI Working Group, but also in the CEC and Commission's Joint Agency Workshop on Vehicle-Grid Integration and Charging Infrastructure Funding as part of the CEC's 2020 Integrated Energy Policy Report Update proceeding.[47]

In general, the Commission's Joint Agency VGI Working Group involved extensive work from stakeholders, and should be utilized to the fullest extent possible. For instance, the Final Report resulting from the Joint Agency VGI Working Group advanced twenty-three short-term recommendations that garnered the strongest agreement among stakeholders—PCE and EBCE fully support these recommendations as a good starting point for further policy reform.[48] Given the substantial effort that has gone into this process, as well as the robust set of resulting policy recommendations flowing out of this process, an additional stakeholder process on VGI would at

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[45] Draft TEF, p. 135.
[46] *Id.*, p. 136.
[47] *Joint Agency Workshop on Vehicle-Grid Integration and Charging Infrastructure Funding*, California Energy Commission, *available at* <u>https://www.energy.ca.gov/event/workshop/2020-06/session-3-joint-agency-workshop-vehicle-grid-integration-and-charging</u>.
[48] *Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group*, p. 38, California Public Utilities Commission DRIVE OIR Rulemaking (R.18-12-006) (June 30, 2020) ("Final VGI Report").

this point only operate to slow deployment. PCE and EBCE also believe the Joint Agency VGI Working Group provided sufficient process and output and no further process is needed at this time.

B. <u>Section 11.1, Stakeholder Question 3</u>: The Draft TEF Should be Revised to Reflect that CCAs are Equal Partners with IOUs in Advancing VGI and Can Serve as Program Administrators of TE Programs, Including VGI Programs.

The Final Report coming out of the Commission's Interagency VGI Working Group recognized the substantial contributions of CCAs in the area of VGI.[49] It also identified CCAs as representing "a large driver of clean energy in California" and as possessing "relevant customer data [which they are using] to inform programs for transportation electrification."[50] Further, it recognized that CCAs are continuing to expand their TE programs, and that therefore, CCAs and IOUs will need to increase planning efforts to ensure that their complementary efforts to advance VGI are well coordinated.[51]

The Draft TEF should be revised to reflect these same conclusions, and specifically, to recognize the significant contributions that CCAs can continue to make in advancing VGI, and that these efforts can be complementary to IOU VGI efforts. To ensure these efforts are indeed complementary, the Draft TEF should be revised to reflect that CCAs have the authority to apply to design and administer their own TE programs—including VGI programs—using the same approval process as utilities. Through this process, in which CCAs and IOUs will work to coordinate the scope of their respective TEPs and program offerings, CCAs will gain access to the funding they need to increase and scale their unique contributions in the area of VGI. Again, while the Joint CCAs will demonstrate more comprehensively through their comments on Section 10 of the Draft TEF why CCAs should be able to serve as program administrators alongside IOUs and how the TEP process can be best coordinated, the Joint CCAs focus here on the substantial contributions CCAs could make as program administrators of VGI programs.

Many examples of CCA VGI programs already in existence demonstrate that CCAs are well-positioned to design VGI programs that complement IOU programs in this space. For instance, PCE's Managed Charging Pilot, a residential actively-managed charging pilot that uses

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[49] Final VGI Report, Annex 1: Materials Produced by the VGI Working Group, Stock-Takes of Existing Efforts (Community Choice Aggregators), *available at* https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-Annexes-6.30.20.pdf.
[50] Final VGI Report, p. 14.
[51] *Id*.

vehicle telematics as a non-hardware based solution, supports PCE's goal of providing 100 percent renewable energy on an hourly time-coincident basis by 2025 by shifting charging demand to times when there is more renewable power supply. PCE has partnered with Flexcharging, a startup that has developed a platform that integrates with EV on-board telematics, to test managed charging. By utilizing the EV, this approach bypasses the need for an internet-connected residential charger for participation once the program has fully developed. This is an excellent solution for renters, in particular, as it does not require the utilization of a charger at home, allowing for potentially much wider participation in VGI programs by enabling the inclusion of EV drivers that charge by plugging into a standard outlet. In addition, the ability to manage Level 1 charging has been incorporated into this pilot, demonstrating how Level 1 charging can play a critical role in delivering the benefits of VGI by moving even lower-power charging to off-peak hours. PCE is currently exploring various incentive structures to utilize with its residential customers when this pilot moves into later phases of development.

In addition, as part of PCE's EV Ready program, an EV infrastructure partnership with CALeVIP, PCE is investigating EV network operators that can provide aggregated curtailment at workplaces with the goal of reducing charging during evening ramp up. This program will also heavily emphasize local site energy management such as circuit and panel sharing and Level 1 charging.[52]

Programs like these also demonstrate how different charging technologies and strategies can effectively contribute to VGI goals. In particular, despite the suggestion of some TE stakeholders,[53] Level 1 charging is not contrary to VGI goals, as VGI can both be enabled by the EV itself on a "dumb" plug or charger,[54] and by smart Level 1 chargers, which have the ability to provide managed charging and curtailment.[55] In addition, concerns regarding the consequences of

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[52] Final VGI Report, Annex 1: Materials Produced by the VGI Working Group, Stock-Takes of Existing Efforts (Community Choice Aggregators), *available at* https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-Annexes-6.30.20.pdf.

[53] R.18-12-006, *Chargepoint, Inc. Reply Comments on Staff Proposal for Draft Transportation Electrification Framework (Sections 7 and 8)*, pp. 7-8 (August 7, 2020).

[54] As one example, the vehicle-based approach was taken in the BMW ChargeForward pilot project originally with PG&E. *See BMW I ChargeForward*, PG&E, https://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf. Companies that are advancing EV-based managed charging technology include FlexCharging, ev.energy, and FleetCarma.

[55] *Cf.* R.18-12-006, *Chargepoint, Inc. Reply Comments on Staff Proposal for Draft Transportation Electrification Framework (Sections 7 and 8)*, p. 7 (August 7, 2020) ("One reason there are no L1 standards 'to control access, collect charging data, and better manage energy usage' is that L1 charging

Level 1 chargers' longer charge times can be managed with outreach aimed at encouraging drivers to charge more frequently on these chargers. In fact, a majority of EV drivers use Level 1 charging today and most plug in every evening.[56] Ten hours of Level 1 charging provides up to 40 to 50 miles of range, which meets the vast majority of daily commute patterns. A ten-hour Level 1 charge window also still allows users the opportunity to participate in managed charging through VGI programs, given that, for instance, a managed charging session from 9 PM to 7 AM is highly preferable from a grid perspective to an unmanaged charge from 6 PM to 4 AM.[57]

SCP has also advanced substantial efforts in the VGI space. Its GridSavvy program utilizes demand-response capable residential EV charging stations to reduce peak load on the grid. Through the program, customers receive a free EV charger and can earn a monthly bill credit for participation.[58] SCP is currently able to dispatch approximately 800 Level 2 car charging stations and can call up to 24 hours of events per month.[59]

SVCE is also in the process of assessing its next steps in launching a virtual power plant, which will incorporate VGI. SVCE partnered with Gridworks to assess five different virtual power plant options, and is using its recent white paper on this topic as its starting point for these efforts.[60] SVCE is also partnering with ev.energy as part of its Innovation Onramp program to use greenhouse gas emissions forecasts and real-time price signals to optimize EV charging in order to minimize carbon emissions while maximizing customers savings.[61]

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stations by design are not capable of enabling these functions as L2 and DCFC charging stations do"). This statement is not correct—this technology for Level 1 chargers is available and is continuing to develop. For instance, companies like Plugzio are advancing Level 1 smart plugs. PCE is also in discussions with additional Level 1 smart plug companies with products under development.

[56] Michael Nicholas, Senior Researcher, International Council on Clean Transportation, "The need for public charging and current progress" at 6 (June 24, 2020), submitted as part of California Energy Commission Docket 20-IEPR-02 (docketed date June 23, 2020), *available at* https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-02.

[57] The managed session would avoid contributing to evening ramp periods—the tail of the "duck curve"—when solar resources go offline as the sun sets and other generation resources on standby are called upon to meet load demand. Also, Level 1 technology has more gradual ramp rates that are easier to manage from a grid management perspective.

[58] *GridSavvy*, Sonoma Clean Power, https://sonomacleanpower.org/programs/gridsavvy.

[59] Final VGI Report, Annex 1: Materials Produced by the VGI Working Group, Stock-Takes of Existing Efforts (Community Choice Aggregators), *available at* https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-Annexes-6.30.20.pdf.

[60] *Id*.

[61] *Silicon Valley Clean Energy Partners with Ev.energy to Launch Zero-Carbon EV Charging in California*, Ev.energy, https://ev.energy/news/svce/.

This sampling of current CCA efforts in the VGI space—as well as other CCA efforts, described further in the Joint Agency VGI Working Group's Final Report[62]—demonstrate the contributions CCAs could continue to offer and scale if permitted to serve as TE program administrators alongside IOUs.

IV. Draft TEF Section 11.2 – ME&O

A. Section 11.2, Stakeholder Question 1: If Program Administrators' Funds for TE ME&O Efforts are Capped, the Cap Should be on the Percent of Each Program Administrator's Overall TE Budget that can go to ME&O.

Some program administrators might rely more substantially than others on ME&O to advance their overall TE efforts. The Joint CCAs generally support allowing for flexibility in program design, to account for local opportunities and constraints, and support flexibility in the area of ME&O as well. Therefore, the Joint CCAs do not believe a cap on ME&O funding is necessary.

However, if the Draft TEF is revised to establish a cap, the cap should be at the program administrator level, i.e., it should operate as a cap on the percent of each program administrator's overall TE funds that can go to ME&O, rather than a cap for each TE program. The establishment of such a cap will allow for different programs to focus on ME&O needs to varying degrees. This variation across TE programs makes sense in light of the fact that certain TE programs may appropriately focus almost entirely on ME&O, while others simply have no need to incorporate ME&O elements. As one example, the main focus of PCE's Community Outreach Small Grants program is to provide outreach to community members to promote clean energy and PCE programs,[63] while other of PCE's TE programs devote minimal funds to outreach efforts.

Additionally, the Joint CCAs submit that if, through this proceeding, there is not consensus on a particular program administrator-level cap, one logical alternative would be for the cap to vary by program administrator. The Commission could set each program administrator's cap during its review of the administrator's TEP, based on the administrator's justifications within its TEP regarding the appropriate cap given the particular circumstances in its service territory.

[62] Final VGI Report, Annex 1: Materials Produced by the VGI Working Group, Stock-Takes of Existing Efforts (Community Choice Aggregators), *available at* https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-Annexes-6.30.20.pdf.
[63] *Community Outreach Small Grants*, Peninsula Clean Energy, https://www.peninsulacleanenergy.com/small-grants/.

V. **<u>Conclusion</u>**

The Joint CCAs appreciate this opportunity to submit comments on Sections 6, 11.1, and 11.2 of the Draft TEF, and urge the Commission to modify the Draft TEF to adopt the recommendations herein with respect to the suggested frameworks for the state's TE efforts in the areas of equity, VGI, and ME&O.

Respectfully submitted,

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On behalf of Peninsula Clean Energy Authority, Redwood Coast Energy Authority, East Bay Community Energy, the City of San José, Marin Clean Energy, Silicon Valley Clean Energy, and Sonoma Clean Power

Dated: August 21, 2020

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

Application of Pacific Gas and Electric Company for Approval of Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for 2021-2026 Program Years. (U39M)	Application 19-11-003
And Related Matters.	Application 19-11-004 Application 19-11-005 Application 19-11-006 Application 19-11-007

COMMENTS OF MARIN CLEAN ENERGY ON THE ADMINISTRATIVE LAW JUDGE'S RULING PROVIDING GUIDANCE AND SEEKING COMMENTS

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August 24, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for 2021-2026 Program Years. (U39M)	Application 19-11-003
And Related Matters.	Application 19-11-004 Application 19-11-005 Application 19-11-006 Application 19-11-007

I. Introduction

As directed by the *Administrative Law Judge's Ruling Providing Guidance and Seeking Comments* ("Ruling"), issued August 19, 2020, Marin Clean Energy ("MCE") respectfully submits the following comments.

II. Comments

A. Given that parties have expressed the need for additional discussion and analyses on the Energy Division Staff Proposal, should the proceeding schedule be modified to accommodate additional time for more meetings/workshops, time to develop budget and goals scenarios, time to prepare responses to data requests related to the staff proposal, etc.? If so, what is your party's proposed change to the schedule? Explain.

MCE supports the vision the Staff Proposal sets forth for the ESA program. However, in its current form it does not provide sufficient detail to serve as guidance for the 2021-2026 program cycle. Several parties have also raised concerns about the achievability and cost of moving the ESA program to the model set forth in the Staff Proposal. Because it is possible that the Commission might adopt the Staff Proposal and find that it should guide the 2021-2026 program cycle, MCE believes that additional time for further analysis is required. MCE does not have a specific amended schedule to propose at this time.

B. How does the COVID-19 pandemic impact the proceeding?

a. Is there an impact on the applications and do they need to be updated? If yes, what are the impacts and what is your party's proposed procedural solution?
b. Is there an impact on party resources and the current schedule? If yes, what is your party's proposed change to the schedule?

MCE does not anticipate the need to update its LIFT 2.0 application in light of the COVID-19 pandemic. MCE does not anticipate any insurmountable impacts to its resources under the current schedule as a result of the pandemic.

C. Are there other impacts in general that affect the proceeding and its schedule? If yes, what are they and what is your party's proposed solution?

MCE is not aware of any other impacts that might impact the proceeding's schedule.

III. Conclusion

MCE appreciates the opportunity to comment on the proceeding's schedule. Further, MCE particularly appreciates the consideration given by the ALJ in this Ruling to the impact the COVID-19 pandemic may be having on parties to this proceeding.

Respectfully submitted,

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August 24, 2020

Submit comment on Hybrid Resource Draft Final Proposal

Initiative: Hybrid resources

1. Please provide your organization’s overall position on the Hybrid Resources draft final proposal:

Choose:

- Support
- Support with caveats X
- Oppose
- Oppose with caveats
- No position

2. Provide a summary of your organization's comments on this proposal:

CalCCA appreciates the CAISO’s continued efforts to develop and refine market participation rules for hybrid resources and co-located resources. CalCCA’s comments focus primarily on the following issues.

I. Improving CAISO’s ability to optimize storage resources in the real time market:
CalCCA encourages CAISO to redouble its efforts to identify a better real time solution than the proposed minimum charge requirement. If it is not feasible to have a longer RTD time horizon than 65 minutes, CAISO should consider one or two reruns of the DAM prior to the beginning of each day and/or prior to the start of the daily storage charging hours.

II. Addressing downward VER deviations for co-located resources:
CalCCA continues to support CAISO allowing for downward VER deviations to be offset by reduced co-located resource charging deviations to avoid unnecessary grid charging. These deviations are necessary to allow storage resources with Investment Tax Credit (ITC) charging restrictions to choose the co-located configuration without risking inadvertent grid charging that can occur because of VER forecast error between the time storage resource bids must be submitted and energy is produced by the VER in real-time.

3. Provide your organization’s feedback on the market interaction for hybrid resources proposal, as described in the draft final proposal:

CalCCA is concerned that CAISO’s “optimization” of hybrid resources in the day-ahead market will be suboptimal, since it will be limited by the collective educated guesses of the hybrid resource operators about which hours will be preferred for charging and discharging of the storage component. Because hybrid operators could face the risk of infeasible day-ahead discharge schedules, we anticipate that these operators may choose to essentially self-schedule day-ahead a potentially significant portion of their combined hybrid resource capability. Unfortunately, this result may be an unavoidable aspect of the hybrid structure, but it points up the importance of making the co-located configuration as attractive as possible for resource owners. This is because the co-located configuration allows the CAISO to optimize each component of the co-located resource. We therefore urge the CAISO to reconsider its decision to not allow co-located storage resources to deviate from dispatch instructions when necessary to avoid inadvertent grid charging as further described in our response to Question 6.

CalCCA reiterates its comments on the RA Enhancements 5th Revised Straw Proposal that CalCCA continues to be concerned about CAISO's inability to optimize storage resources in the real-time market. The examples in Tables 14 and 15 of the RA Enhancements 5th Revised Straw Proposal illustrate the inefficiencies that will be created by this failure. For example, Table 15 shows that 50 MWh of available bid-in storage energy that otherwise would have cleared the RTM for HE18 is blocked by the 80 MWh minimum charge requirement and then none of the energy that was being preserved by the minimum charge requirement clears any of the subsequent intervals. This outcome will result in increased costs for consumers and increased risks for generators. The minimum charge requirement is a poor substitute for a better optimized real-time market solution with a longer time horizon to avoid the suboptimal result illustrated by Table 15.

CalCCA encourages CAISO to redouble its efforts to identify a better real time solution. If it is not feasible to have a longer RTD time horizon than 65 minutes, CAISO should consider one or two reruns of the DAM prior to the beginning of each day and/or prior to the start of the daily storage charging hours. The results of the DAM rerun(s) would have the benefit of much better-informed load and VER forecasts, additional information regarding generation and transmission outages, and more up-to-date storage state of charge information from the RTM. The DAM rerun could then be used to set minimum charge requirements that would be better aligned with RTM conditions for the remainder of the RTM intervals.

4. Provide your organization's feedback on the forecasting and dynamic limits proposal, as described in the draft final proposal:

CalCCA supports CAISO's forecasting and dynamic limits proposals, as described in the draft final proposal.

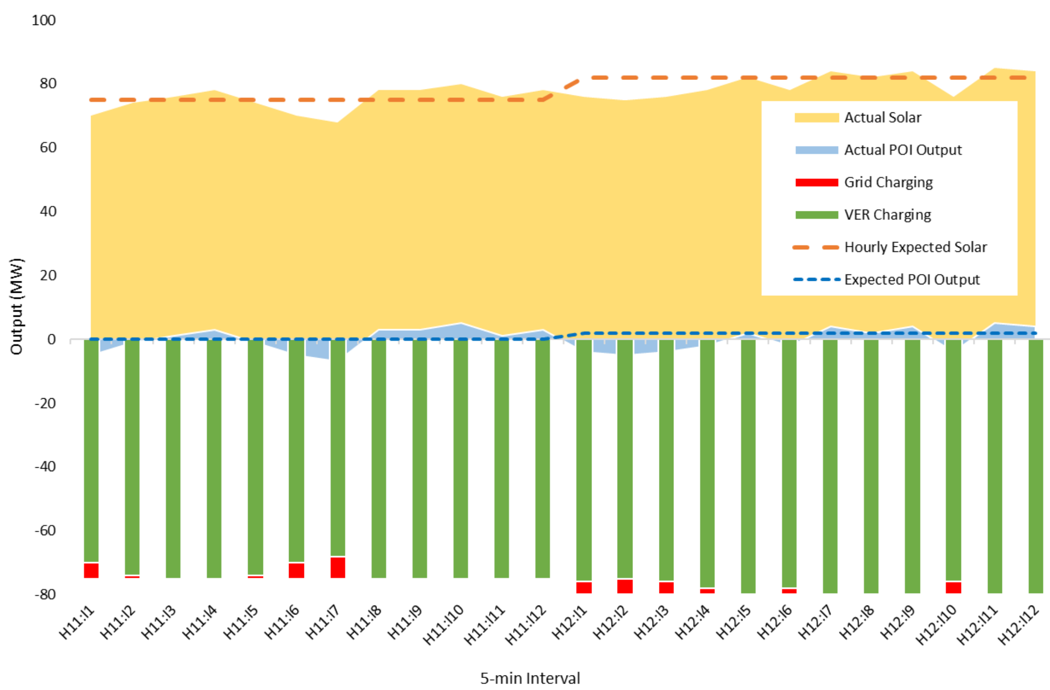
5. Provide your organization's feedback on the proposal to enhance the aggregate capability constraint for co-located resources, as described within the draft final proposal:

CalCCA supports CAISO's proposal to enhance the aggregate capability constraint for co-located resources, as described in the draft final proposal.

6. Provide your organization's feedback on the proposal to allow co-located storage resources to deviate from dispatch instructions to allow for offsetting VER variation, as described within the draft final proposal:

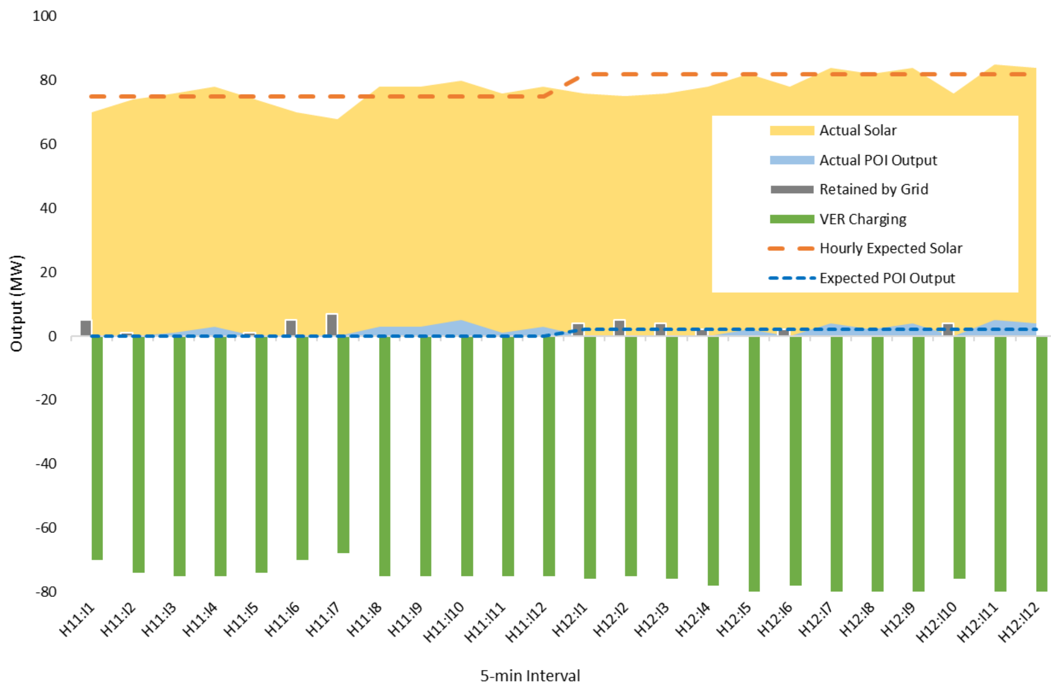
While the proposal to allow co-located storage resources to deviate from dispatch instructions to allow for offsetting VER variation described in the draft final proposal is a step in the right direction, it falls short. CAISO also should allow for downward VER deviations to be offset by reduced co-located resource charging deviations. These deviations are necessary to allow storage resources with Investment Tax Credit (ITC) charging restrictions to choose the co-located configuration without risking inadvertent grid charging that can occur because of VER forecast error between the time storage resource bids must be submitted and energy is produced by the VER in real-time. Figure 1 below illustrates how these forecast error deviations would occur if CAISO does not allow co-located storage resources to deviate from their Dispatch Instructions under the circumstance in which the co-located VER deviates in the downward direction below the level of charging Dispatch Instruction for the co-located storage resource. The inadvertent grid charging that would result either will reduce the ITC benefits of the storage resource or will motivate resource operators to schedule their co-located resources in such a manner that CAISO will not have as much storage capacity available to it or will have more upward uninstructed imbalance energy from VER resources. Neither outcome is desirable.

Figure 1. Output without Downward Deviation Rule



CalCCA urges CAISO to allow the co-located storage resource to deviate from its charging schedule as necessary to avoid inadvertent grid charging due to real-time market VER forecast error. We understand that there may be a concern that this will result in the co-located storage resource having a reduced state of charge for subsequent use. We believe that this concern does not acknowledge the likelihood that either i. some other storage resource that is providing regulation up will provide the energy needed to charge the co-located storage resource whose companion VER is producing less than forecast, or ii. a thermal regulating resource may provide the imbalance energy, resulting in increased GHG emissions. Either result is not desirable. Figure 2 below illustrates that rather than charging from the grid, the unexpected downward deviation in solar output is offset with reduced storage charging in that interval. The result is that for the co-located resource shown, the state of charge is lower than was expected by the 5-minute forecast, however another storage regulation resource likely will have retained its state of charge to offset this deviation. Note that by allowing the storage resource to deviate from its charge schedule when solar output is lower than expected, the actual output at the point of interconnection (POI) for the co-located resource is closer to the expected schedule if downward deviations are allowed, and the amount of VER production and storage resource charging from the co-located resource is the same with or without the downward deviation rule.

Figure 2. Output with Downward Deviation Rule



7. Provide your organization's feedback on the metering topic, as described within the draft final proposal:

CalCCA supports CAISO's metering proposal, as described in the draft final proposal.

8. Provide your organization's feedback on the ancillary services proposal, as described within the draft final proposal:

CalCCA supports eligibility of hybrid and co-located resources for providing ancillary services.

9. Provide your organization's feedback on the resource adequacy topic, as described in the draft final proposal:

During the August 10 stakeholder call, some stakeholders noted that CAISO's proposal to use outage cards for hybrid resources could result in these resources being double penalized by potential UCAP reductions and by CPUC counting rules. The CPUC's hybrid counting rules already discount the VER portion in the ELCC calculations and for expected storage charging. Further reductions to UCAP resulting from the use of outage cards would unfairly penalize these resources. Additional work is needed to ensure CAISO's treatment of hybrid resources is not inconsistent with the CPUC counting rules.

CalCCA also seeks clarification that hybrid resources that submit bids for the full range of their resource adequacy obligations will not need to submit outage cards for the amount of capacity reflected in their bids. For example, a hybrid resource with a solar forecast to produce at a consistent output of 80 MW for several hours that plans to use a 50 MW portion of that output to charge the on-site battery if prices are below a given level, but is willing to deliver the full 80 to the grid if prices are above a given level, would not need to submit an outage card for 50 MW for the VER component.

Similarly, for the storage component, if there is available stored energy and the resource bids reflect a willingness to discharge the full 50 MW associated with the storage component if prices exceed a given level, no outage card would be needed even if the resource operator plans to charge the storage resource.

10. Provide any additional comments on the draft final proposal for the Hybrid Resources initiative:

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	)))))	Rulemaking 19-09-009 (Filed September 19, 2019)

REPLY COMMENTS OF THE JOINT CCAS
ON TRACK 2 PROPOSALS

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August 28, 2020

On Behalf Of:
Peninsula Clean Energy Authority
Sonoma Clean Power Authority
Redwood Coast Energy Authority
San Jose Clean Energy
Pioneer Community Energy
California Choice Energy Authority
Monterey Bay Community Power
San Diego Community Power
East Bay Community Energy
Marin Clean Energy

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	)))))	Rulemaking 19-09-009 (Filed September 19, 2019)

REPLY COMMENTS OF THE JOINT CCAS
ON TRACK 2 PROPOSALS

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the July 23, 2020 *Administrative Law Judge's Ruling Requesting Comment on Track 2 Microgrid and Resiliency Strategies Staff Proposal, Facilitating the Commercialization of Microgrids Pursuant to Senate Bill 1339* (the "Ruling"), the Joint CCAs[1] hereby submit the following reply comments on the Track 2 Staff Proposal ("Staff Proposal") provided as Attachment 1 to the Ruling. In these reply comments, the Joint CCAs address points raised by a number of parties in their respective opening comments.

I. GENERAL REPLY COMMENTS

A. The Joint CCAs Agree That A Comprehensive Microgrid Tariff Is Needed To Commercialize Microgrids

The Joint CCAs concur with the numerous parties, including California Energy Storage Alliance ("CESA"), Applied Medical, California Solar and Storage Association ("CALSSA"), Google, Green Power Institute ("GPI"), Microgrid Resources Coalition ("MRC") and many

[1] The Joint CCAs consist of the following Community Choice Aggregation ("CCA") programs: Peninsula Clean Energy Authority ("PCE"); Sonoma Clean Power Authority ("SCP"); Redwood Coast Energy Authority ("RCEA"); San Jose Clean Energy ("SJCE"); Pioneer Community Energy ("Pioneer"); the California Choice Energy Authority ("CalChoice"); Monterey Bay Community Power ("MBCP"); San Diego Community Power ("SDCP"); East Bay Community Energy ("EBCE"); and Marin Clean Energy ("MCE").

others that submitted comments urging the Commission to take additional steps beyond the Staff Proposal to facilitate the commercialization of microgrids. As the Energy Division has recognized, "microgrids" encompass a range of potential arrangements. The Joint CCAs agree with Google and MRC that in order to meet its statutory mandate, the Commission must create a fair and competitive marketplace for all microgrid types and ownership arrangements currently allowed by statute.[2] Further, the Joint CCAs agree with MRC and others that the first, most critical step towards achieving this goal is the development of a comprehensive microgrids tariff.[3]

The Joint CCAs appreciate the size and challenging nature of the task before the Commission, and recognize the Energy Division's tremendous work thus far. The Staff Proposal undoubtedly moves the ball forward, and, perhaps more importantly, the Staff Concept Paper provides a solid roadmap and framework for achieving microgrid commercialization. While a number of parties submitted comments that could be viewed as critical of the Staff Proposal for not addressing the required range of microgrid types, these comments should be viewed as an encouraging sign – evidence that a wide range of parties are enthusiastically dedicated to working towards the tariff and regulatory reforms needed to achieve the full commercialization of microgrids required by SB 1339.

While the Joint CCAs recognize that at least some of these broader commercialization issues may be more challenging than those addressed in the Staff Proposal, this is not a burden that the Energy Division must – or should – bear alone. Many parties are in close alignment on key commercialization issues, and some of the most challenging work has already been done.

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2 *See*, Google Opening Coments at 2-3; MRC Opening Comments at 3-4.

3 MRC Opening Comments at 3-4, 30.

MRC, for instance, has provided an outline for a general microgrids tariff.[4] The Joint CCAs have conducted an initial review of this outline, and believe that it provides a solid starting point for the tariff development process. Stakeholder feedback could be used to refine and flesh out the tariff structure set forth in the outline. Similarly, as noted in the Joint CCAs' opening comments,[5] RCEA and PG&E have made significant progress towards developing a tariff structure for the Redwood Coast Airport Microgrid. Many of the principles developed and lessons learned from this effort can be used to inform the microgrids tariff development process.

It is critical that the Commission develop a *unified* and *holistic* Microgrid tariff in this Rulemaking. The IOUs must not be allowed to develop an inefficient and fragemented microgrid tariff structure, or, even more problematically, attempt to implement Microgrid Tariffs through advice letters or in other Commission proceedings without proper context and stakeholder input, as both instances would impose additional barriers to microgrid commercialization. The Joint CCAs are very concerned by PG&E's attempt to "sneak through" a *general community-scale microgrid tariff* in its Community Microgrids Enablement Program ("CMEP") Advice Letter, AL 5918-E. This is a major tariff proposal that would apply to all community-scale microgrids that are being brought to PG&E under CMEP. Given PG&E's resources, market position, and the significant investment in CMEP, PG&E's tariff proposal is likely to be a dominant and precedent-setting tariff for customer-sited and community microgrids in PG&E's servive area. Considering such a major tariff proposal through the Advice Letter process not only violates due process and General Order 96-B, but also frustrates the purpose of this Rulemaking, and, by excluding proper stakeholder input, is likely to create barriers to

4 MRC Opening Comments at 30-38.
5 Joint CCA Opening Comments at 5.

microgrid commericializaiton in violation of SB 1339. PG&E's proposal should be considered as part of an overall microgrid tariff development process in this Rulemaking.

B. The Commission Should Consider Recommending Changes To Section 218 To The Legislature

The Joint CCAs agree with the numerous parties, including AMR, CalSSA, and MRC, that noted that Public Utilities Code Section 218 ("Section 218"), as currently worded, presents a significant barrier to the full commercialization of Microgrids. Many of these parties asked that the Commission take steps to encourage the Legislature to modify Section 218. As a general matter, the Joint CCAs support this recommendation. While it is certainly true that the Legislature has the sole authority to change Section 218, that does not mean that the Commission does not have a voice in this matter. The Commission regularly serves an advisory function for the Legislature. The Commission should consider exercising this advisory function by providing the Legislature with a white paper that identifies the barriers to microgrid commercialization that Section 218 imposes and recommends potential changes to the statutory language to remove these barriers. The Staff Concept Paper provides a deep dive the barriers created by Section 218 and offers, as one option for addressing these barriers, that the Commission could recommend that the Legislature amend Section 218 to create a new "microgrid" entity that would be allowed to distribute electricity across property lines and roads, to multiple parcels (adjacent or non-adjacent).[6]

The Joint CCAs strongly support Staff's proposal that Commission recommend modifications to Section 218 to the Legislature, and view the proposed creation of a separate "microgrid" entity as an intriguing and promising approach. At the same time, the Joint CCAs believe that any recommended modifications to Section 218 should be carefully vetted by the

[6] Staff Concept Paper at 39-40, 43.

Commission and stakeholders before being submitted to the Legislature. Section 218 serves important consumer protection and safety functions, and any modifications to Section 218 must ensure that enabling microgrid commercialization and deployment does not compromise these important policies. Changes to Section 218 will require a nuanced approach, not a blanket exception. Staff's proposal to create a new "microgrid" entity may be a good starting point for developing such an approach. A workshop process, similar to the process recommended by the Joint CCAs for the development of a general microgrids tariff,[7] is one potential way to develop and vet a Section 218 white paper.

II. REPLY COMMENTS ON STAFF PROPOSALS

A. Reply To Comments On Staff Proposal 2

i. The Joint CCAs Oppose SCE's Proposed Restrictions On Microgrid Operations On Adjacent Parcels During PSPS Outages

The Joint CCA's oppose SCE's proposal to restrict Proposal 2 microgrid operation during PSPS outages. SCE states that:

> …it is important to assure that microgrids do not operate during unsafe [PSPS] conditions. That is not to say that microgrids cannot operate during some types of outages – for example, a repair outage on a portion of a line could permit for safe operations of a microgrid in an adjacent area. The key factor here is to require microgrid operators to coordinate with the neighboring IOUs and operate only in a manner that is consistent with the safety of the public and the safe operation of IOU facilities in the area.[8]

While it is not entirely clear what SCE envisions as appropriate requirements for ensuring that microgrid operators "coordinate" with their distribution IOUs and operate only in a manner consistent wit hteh safe operation of IOU facilities, it appears that SCE is implying, if not outright proposing, that Microgrid operators be required to secure IOU permission or clearance

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7 Joint CCA Opening Comments at 2-4.

8 SCE Opening Comments at 7-8.

before operating their microgrids during PSPS events. The Commission should reject this proposal.

SCE's proposal would undermine the Commission's policy of encouraging the use of microgrids to mitigate the impacts of PSPS outages. Microgrids are a critical tool for improving community resiliency, particularly when microgrids are used to provide backup power to critical facilities and infrastructure ("CFI") needed for public health and safety. Microgrids are particularly critical for mitigating the impacts of PSPS outages, which, as demonstrated by 2019's massive PSPS events, present the greatest outage threat to CFI operators. SCE's proposal would create an unacceptable risk that CFI operators would not be able to use their microgrids to provide backup power during PSPS events. As the records in the PSPS Rulemaking (R.18-12-005) and PSPS Order Instituting Investigation (I.19-11-013) thoroughly demonstrate, the IOUs handling of PSPS outages has been plagued by large-scale notification and communication failures and a lack of coordination with local and tribal governmental entities (including CCAs) and CFI operators. Given these systematic failures, SCE's proposal would create an unacceptable barrier to the use of microgrids for resiliency.

SCE's proposal is based on a grossly exaggerated premise and as such is unjustified. SCE claims that "energized wires, regardless of who owns and operates them, can pose the exact same risk to public safety during extreme weather events." As a threshold matter, this concern simply isn't applicable to microgrids in lower-risk Tier 1 HFTDs, including in low-risk areas that may still be subject to transmission-related PSPS outages. Further, SCE's claim ignores the fact that Proposal 2 microgrids and the large-scale transmission and distribution systems operated by IOUs are radically different, both in terms of their physical structure and the wildfire risk associated with their operation. First, a Proposal 2 microgrid would involve a single (or small number) of lines connecting two adjacent parcels. Even if the adjacent parcels are large (for instance parcels housing a fire station and a hospital) a Proposal 2 microgrid would likely require no more than a few hundred feet of conductor at most. In contrast, the IOUs initiate PSPS outages in order to reduce fire risk for transmission lines and distribution circuits that may include hundreds or thousands of miles of conductor. All things being equal, the odds of an ignition event occurring on such short lengths of conductor are comparatively insignificant. Second, Proposal 2 microgrids are likely to be located in developed areas, including structures and paved areas like walkways and parking lots. Such areas have significantly lower chances of wildfire ignition (often from falling branches), and, due lack of dry plant matter for fuel in developed areas, a much lower risk of fire spread than the high-risk wilderness and rural areas covered by the IOU's transmission and distribiution systems. Developed areas are also much more accessible to firefighters and ignitions in such areas are less likely to become uncontrolled wildfires. Third, it is reasonable to expect that most Proposal 2 microgrids will have underground lines, completely eliminating any PSPS-related wildfire risk.

In the balance, SCE's proposal would impose a significant risk of interrupting microgrids' ability to contribute to resiliency during PSPS outages with little, if any corresponding improvement to safety. While safe operation of microgrids is critical at all times, including during PSPS events, there is no justification for restricting resiliency microgrid operation during PSPS outrages or giving IOUs the power to impose such restrictions.

ii. The Commission Should Reject Arguments In Favor Of The 10 Project Cap for Microgrids Serving Adjacent Parcels

In opening comments a small handful of parties, including PG&E and SCE, expressed support for limiting Proposal 2 projects to a total of 10 microgrids within the combined territorty of the three IOUs. The Commission should reject the proposed 10 project cap. As the

Commission has repeatedly recognized, the State has an immediate and urgent need for ways to mitigate the impact of PSPS events. The express purpose of Track 1 of this proceeding was to find ways to use Microgrids to improve resiliency. Proposal 2 microgrids are a straightforward, low-hanging fruit resiliency solution. In light of the *urgent* need to improve resiliency, the Commission should do everything in its power to encourage the widespread adoption of Proposal 2 microgrids as quickly as possible. In the current context, a 10 project cap would impose an unconscionable delay.

The arguments in favor of a 10 project cap revolve around vague assertions regarding "unanswered questions" and making sure that Proposal 2 microgrids don't have any unintended consequences. These arguments are completely unfounded. There are no questions left to answer. Microgrids are a mature technology, and Proposal 2 microgrids (connecting two adjacent parcels) are one of the simplest microgrid designs possible. All equipment needed for Proposal 2 microgrids is already either commercially available or well within the capability of existing technology. On a policy level, because Proposal 2 microgrids would only provide power from one premise to a second adjacent premise during outages, there is little danger of price manipulation.

B. Reply To Comments On Staff Proposal 3

i. The Commission Should Reject The IOUs' Arguments Against Cost Responsibility Surcharge Exemptions

In Opening Comments each of the IOUs presented arguments against the Proposal 3, Options 1-3 Cost Responsibility Surcharge ("CRS") exemptions. Each of the IOUs' objections boils down to the claim that exempting microgrids from CRS would result in cost-shifting from the microgrid operators to other customers. This objection is fundamentally incorrect.

The Staff Proposal would create four distinct CRS exemptions, summarized in the following table:

Criteria	Proposed Additional Exemption from Cost Responsibility Surcharges		
	Departing Load Charges	Standby Reservation Charges	Nonbypassable Charges*
New or Incremental Load	Yes	No	No
Long Duration or Indefinite Islanding	No	Yes	No
New or Incremental Load and Long Duration or Indefinite Islanding	Yes	Yes	No
Long Duration or Indefinite Islanding for Critical Facilities	Yes	Yes	Yes
All Others	No	No	No

As a practical matter, these exemptions are necessary to protect microgrids from *reverse* cost-shifting – shifting costs from general customers to microgrids by making microgrids pay for costs that they neither cause nor benefit from.

More importantly, CRS exemptions are justified to compensate microgrid operators for the general benefits that they provide to the grid. The Joint CCAs agree with MRC that resiliency is a microgrid resource attribute that has a significant real-world value for both the public and the IOUs.[9] Microgrid resiliency benefits the public by reducing the impact of outages, including disruptions to services critical to public health and safety. Increased resiliency benefits the IOUs by reducing the harms (and potential liability) caused by their PSPS events and other outages. Resiliency microgrids may also reduce the need for ratepayer-funded resiliency investments, may reduce the overall cost of PSPS mitigation, and may free up PSPS mitigation resources for deployment to communities that otherwise may not receive them.

[9] MRC Opening Comments at 4.

The fact that the Commission does not currently have a methodology for assigning an exact value to resiliency should not prevent the Commission from recognizing that resiliency value exists. Ignoring the resiliency value created by microgrids would itself be an unlawful cost shift, as microgrid operators would not be compensated for the full value of the benefits they provide to the grid. Until a more exact resiliency valuation methodology is developed, the Proposal 3, Option 1 cost surcharge exemptions from the Staff Proposal are the most reasonable way to compensate microgrids for the resiliency benefits they provide.

In recognition of the concerns raised by the Center for Accessible Technology,[10] the Joint CCAs would support a slight modification to the Option 1 exemption – microgrids that are generally exempt from NBCs should still be required to pay Public Purpose Program surcharges.

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[10] Center for Accessible Technology Opening Comments at 1-3.

III. CONCLUSION

The Joint CCAs thank the Commission for their consideration of the matters discussed herein.

Dated: August 28, 2020

Respectfully submitted,

/s/David Peffer

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On Behalf Of:

Peninsula Clean Energy Aurthority
Sonoma Clean Power Authority
Redwood Coast Energy Authority
San Jose Clean Energy
Pioneer Community Energy
California Choice Energy Authority
San Diego Community Power
Monterey Bay Community Power
East Bay Community Energy
Marin Clean Energy

SEPTEMBER 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 Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) TRACK 3.A WORKING GROUP REPORT ON CONSENSUS AND NON-CONSENSUS ITEMS REGARDING DEVELOPMENT OF LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND PROPOSAL ON TREATMENT OF EXISTING CONTRACTS

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Dated: September 1, 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 Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) TRACK 3.A WORKING GROUP REPORT ON CONSENSUS AND NON-CONSENSUS ITEMS REGARDING DEVELOPMENT OF LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND PROPOSAL ON TREATMENT OF EXISTING CONTRACTS

Pursuant to the schedule set forth in (i) Ordering Paragraphs 5 and 6 in the June 11, 2020 Decision (D.) 20-06-002 and (ii) the July 7, 2020 *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling* and in accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Community Choice Association ("CalCCA"), on behalf of itself and Pacific Gas and Electric Company ("PG&E") (together, the "Co-Chairs"), respectfully submits this final Track 3.A Working Group report, attached hereto as Attachment 1, on consensus and non-consensus items regarding the Local Capacity Requirement ("LCR") Reduction Compensation Mechanism ("RCM") and Treatment of Existing Contracts ("Report"), which also includes a proposal on treatment of existing contracts, as required in Ordering Paragraph 6 of D.20-06-002.[1]

The Report also provides parties' informal comments addressing and considering the issues included in Ordering Paragraphs 5 and 6 of D.20-06-002:[2]

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[1] Pursuant to Rule 1.8(d), counsel for CalCCA certifies that PG&E has authorized CalCCA to sign and tender this document and to make the representations stated in Rule 1.8(b) on PG&E's behalf.
[2] D.20-06-002, Ordering Paragraphs 5-6 at 92-93.

- Resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources;

- How granular the premium should be (*e.g.*, should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);

- How to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

- Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process;

- How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements; and

- Treatment of existing contracts, including consideration of whether any proposed LCR RCM should be applied to these contracts.

Although not directly related to the LCR RCM design or treatment of existing contracts, the Report also provides and summarizes parties' informal comments responding to the directive for the working group to consider "how the CPE will incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small." [3]

The Report includes the following appendices documenting the formal working group process:

Appendix A	JULY 6, 2020 SERVICE EMAIL
Appendix B	JULY 20, 2020 INFORMAL COMMENTS
Appendix C	JULY 27, 2020 WORKING GROUP WORKSHOP PRESENTATIONS
Appendix D	AUGUST 3, 2020 INFORMAL COMMENTS
Appendix E	AUGUST 17, 2020 INFORMAL REPLY COMMENTS
Appendix F	AUGUST 26, 2020 INFORMAL COMMENTS ON DRAFT REPORT
Appendix G	FINAL MATRIX OF PARTY POSITIONS

[3] *Id.* at 44-45.

The Co-Chairs appreciate the opportunity to submit this Report.

September 1, 2020

Respectfully submitted,

Evelyn Kahl
General Counsel to the
California Community Choice Association

ATTACHMENT 1 TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)[1] TRACK 3.A WORKING GROUP REPORT ON CONSENSUS AND NON-CONSENSUS ITEMS REGARDING DEVELOPMENT OF LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND PROPOSAL ON TREATMENT OF EXISTING CONTRACTS

WORKING GROUP REPORT

[1] Portions of this report written by PG&E, which include Sections I.A, II.B, III.B, IV, and V, were prepared by Erica Brown, Rhett Kikuyama, Luke Nickerman, Greg Rybka, Lisa Wan, and Noelle Formosa.

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Working Group Report on Consensus and Non-Consensus Items Regarding Development of Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Proposal on Treatment of Existing Contracts

I. Background

A. Procedural Background and Scope

Decision (D.) 20-06-002 adopts implementation details for the central procurement of multi-year local resource adequacy (RA) to begin for the 2023 compliance year in the Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) distribution service areas, including identifying PG&E and SCE as the central procurement entities (CPE) for their respective distribution service areas and adopting a hybrid central procurement framework.[2] The framework places full local RA procurement responsibility on behalf of all load serving entities (LSE) on the CPE, and LSEs no longer receive individual local requirements.[3] LSEs that have procured local resources may "(1) show the resource to reduce the central procurement entity's (CPE) overall local procurement obligation and retain 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."[4] Under the "show" option, the LSE does not receive one-for-one credit for its local resources.[5]

In adopting the hybrid central procurement framework, the California Public Utilities Commission (Commission) found that, even without a financial crediting mechanism, the framework does not disincentivize procurement of local resources because LSEs procure local

2 D.20-06-002 at 1, Ordering Paragraphs 2-4.
3 *Id*. at 22-23, Ordering Paragraph 3.
4 *Id*. at 23, Ordering Paragraph 4.
5 *Id*. at 23.

resources for many reasons beyond the local RA value.[6] The Commission recognized, however, that "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas."[7] To that end, the Commission committed to developing an "LCR reduction compensation mechanism, if details can be assessed and developed."[8] The Commission defined "LCR reduction compensation mechanism" as a "financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value."[9] To develop such a mechanism, the Commission directed a working group (WG) co-led by CalCCA and either PG&E or SCE.[10] The Commission also included within the scope of the WG issues related to treatment of existing contracts, including potential application of the LCR RCM to these contracts.[11] The Commission further required the co-leads to file a WG report on consensus and non-consensus items (Report) in this proceeding by September 1, 2020. In addition, the assigned Commissioner in this proceeding issued the *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling*, dated July 7, 2020 (Amended Scoping Memo), designating evaluation of an LCR RCM as an issue in Track 3.A and requiring WG reports and proposals from parties to be filed on September 1, 2020.

In both D.20-06-002 and the Amended Scoping Memo, the Commission identified four specific issues to be addressed by the Report:[12]

a. How granular the premium should be (*e.g.*, should different premiums be developed for different types of preferred resources, for new versus existing

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6 *Id*. at 40-41, 72.
7 *Id*. at 42, 72.
8 *Id*., at 43.
9 *Id,* at 42.
10 *Id.* at Ordering Paragraph 5.
11 *Id.* at 46, 75 and Ordering Paragraph 6.
12 *Id.* at Ordering Paragraph 5.

resources, and/or for sub-local areas, individual local areas, or TAC-wide local areas);

b. How to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

c. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process; and

d. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

In addition, the Commission directed in D.20-06-002 that the Report "address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources."[13] D.20-06-002 also requires the WG to (i) "consider and submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing contracts"[14] and (ii) consider how the CPE will incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small."[15] The Report must also address consensus and non-consensus items regarding treatment of existing contracts.[16]

Using this guidance, CalCCA and PG&E, serving as WG co-leads, sent an email to the service list on July 6, 2020, soliciting initial input from stakeholders through informal comments submitted on July 20, 2020, and seeking participation by other stakeholders with an interest in

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13 *Id.* at Ordering Paragraph 5. The Amended Scoping Memo includes a similar requirement. Amended Scoping Memo at 3.

14 *Id.* at Ordering Paragraph 6.

15 *Id*. at pp. 44-45. The four issues identified above (a.-d.) and the three issues identified in this paragraph (i.e. in the first sentence and romanettes (i) and (ii) of the second sentence) are referred to herein as the "7 Issues." The 7 Issues are also outlined in the email attached as Appendix A.

16 *Ibid*.

presenting at a WG workshop on the identified issues set for July 27, 2020.[17] Eight parties submitted informal comments on the 7 Issues on July 20, 2020 ahead of the July 27, 2020 WG workshop. These informal comments are attached as Appendix B to this Report. Three parties (PG&E, CalCCA, and San Diego Gas & Electric Company (SDG&E)) expressed interest in presenting at the WG workshop. The co-leads facilitated the WG workshop by WebEx on July 27, 2020, beginning at 10:00 a.m. The co-leads jointly presented a review of the 7 Issues identified in D.20-06-002 and initial informal comments on the 7 Issues. Additionally, PG&E made a presentation as a participant in the WG to address pending issues. CalCCA also presented as a WG participant, offering two proposals. The only other party presenting a proposal was SDG&E. These presentations are attached as Appendix C. WG participants submitted informal comments and replies regarding the WG workshop on August 3, 2020, attached as Appendix D, and on August 17, 2020, attached as Appendix E, respectively. A draft of the Report was circulated to WG participants on August 21, 2020, with informal comments on the draft Report submitted on August 26, 2020 and attached here as Appendix F.

The workshop and parties' informal comments have helped inform this Report.

B. Topics Expressly Excluded from Scope

The Commission expressly identified certain topics as out-of-scope.[18] They include:

1. One-for-one credit mechanism for local RA that does not account for relative effectiveness of shown resources relative to bid resources;[19]

2. Ex-post price premium based on the average price paid by the CPE for resources in the local area for which a resource is shown;[20]

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[17] The email to the service list laying out the WG schedule is attached as Appendix A.

[18] D.20-06-002 at 43 ("The Commission is not open to considering a one-for-one credit, CalCCA's proposed financial credit mechanism, or a credit mechanism for fossil fuel resources (other than potentially for existing grandfathered contracts).").

[19] *Id*. at 41.

[20] *Id*. at 42.

3. Credit mechanism for fossil fuel resources (other than potentially for existing contracts);[21] and

4. An LCR RCM mechanism for the SDG&E Transmission Access Charge (TAC) area, where a CPE will not be designated at this time.[22]

Stakeholders generally adhered to this guidance in offering proposals presented through the WG process and described in this Report.

C. Schedule of Completed Activities

The co-leads scheduled and completed the following WG activities:

Date	Activity	Status
July 6, 2020	Co-leads circulated notice to the service lists of WG co-leads and WG schedule, including workshop, and request for informal comments on 7 Issues outlined in D.20-06-002 on pages 43-45 and in Ordering Paragraphs 5 and 6.	Complete
July 17, 2020	Co-leads circulated notice of workshop date and call-in information to the service lists.	Complete
July 20, 2020	Parties submitted informal comments to the service lists in response to the co-leads' request on 7 Issues outlined in D.20-06-002 and notified co-leads of intent to present at workshop.	Complete
July 24, 2020	Co-leads circulated notice of agenda and presentation materials for the virtual workshop to service lists.	Complete
July 27, 2020	Co-leads hosted a virtual workshop on WebEx on LCR RCM and the treatment of existing contracts.	Complete
July 30, 2020	Co-leads again circulated presentations from virtual workshop to workshop participants, in addition to a matrix for parties to utilize in developing informal comments on the workshop.	Complete

21 *Id.* at 41.
22 *Id.* at Conclusion of Law 6.

July 31, 2020	Co-leads circulated updated schedule for WG to the service lists, including dates for informal reply comments on workshop, issuance of a draft Report, and informal comments on the draft Report.	Complete
August 3, 2020	Parties submitted informal comments on the workshop to co-leads, which were circulated to the service lists on August 4, 2020.	Complete
August 17, 2020	Parties submitted informal reply comments on the August 3 informal comments to the service lists (PG&E's informal reply comments were sent to the co-leads on August 17, 2020, and to the service lists on August 19, 2020).	Complete
August 20, 2020	Co-leads circulated an updated schedule for the WG to the service lists	Complete
August 21, 2020	Co-leads served a draft Report to the service lists for comment.	Complete
August 26, 2020	Parties submitted informal comments on the draft Report to the service lists.	Complete
September 1, 2020	Co-leads filed and served Report.	Complete

II. Guiding Principles and Objectives

The co-leads presented their views and interpretations on guiding principles and objectives in the July 27, 2020 workshop presentations.

A. Guidance from D.20-06-002

Drawing from D.20-06-002, the co-leads identified the following explicit guidance provided by the Commission, with the corresponding page number or ordering paragraph (OP) in brackets:

Effectiveness:

1. The LCR RCM cannot provide a "one for one" premium as CalCCA proposed without considering effectiveness. [p. 41]

2. The LCR RCM must address “local effectiveness” and “use limitations” of the shown resource to align the financial compensation with the actual LCR megawatt (MW) reduction the resource provided. [p. 42, OP 5]
3. The WG should consider how to adjust payments to an LSE “from year to year to account for changes in the effectiveness of the resource reducing local requirements.” [OP 5.d.]
4. CPE selection criteria must include (1) “Local effectiveness factors, as published in the California Independent System Operator’s Local Capacity Requirement Technical Studies” [OP 14.b.] and “Energy-use limitations” [OP 14.h.]

<u>Least-Cost, Best-Fit:</u>

a. “Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSE’s seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE” [p. 42]
b. “[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources” [p. 42]
c. “[E]nsures that ratepayers are: (1) only compensating resources to the extent they provide ratepayer value…” [p. 43]

<u>Premium Determination and Market Power Issues:</u>

1. The LCR RCM should “only compensate [] LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs” [p. 43]
2. “[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources” [p. 42]
3. A “benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums” [p. 42]
4. “To the extent that market power inflates local area capacity prices, an ex post benchmark would exacerbate this problem by providing inflated prices to local resources shown by LSEs” [p. 42]
5. The WG must determine “[h]ow to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices.” [OP 5.b]

<u>Preferred Resource Development in Local Areas</u>

1. “a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas.” [p. 41]

B. PG&E Proposed Principles

Based on the guidance in D.20-06-002, PG&E outlined the following four recommended principles for the LCR RCM in its workshop presentation included in Appendix C:

- The LCR RCM should:
    - Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;
    - Reflect the effectiveness of a resource at meeting reliability requirements to prevent “leaning” by LSEs;
    - Result in lower total costs to customers without sacrificing local area reliability; and
    - Not be reflective of market power and/or introduce gaming opportunities but may reflect a “premium” based on the additional cost of developing resources in local areas.

WG participants also provided recommendations and comments on guiding principles. The Alliance for Retail Energy Markets (AReM) proposed the following principles in the evaluation of the need and structure for any such compensation mechanism:

- No CPE Over-procurement – The ability for an LSE to receive an LCR RCM payment from the CPE must not result in over-procurement by the CPE with those costs spread among all LSEs;
- Cost Causation – Customers of LSEs with procurement costs above the CPE’s auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; costs should not be spread to other LSEs or their customers;
- Premiums Paid for Shown Resources Must Be Aligned with the Auction – LSEs with resource types that are worth a premium to the CPE should be eligible for compensation up to that premium, *i.e.*, if the CPE auction awards a higher RA price to energy storage, any LSE-shown resource that is energy storage should be eligible for the LCR RCM premium that does not exceed the premium paid for such resources in the auction; and
- Payment Length for Show Resources Must Be Aligned with the Local RA Requirement – The number of years an LSE is eligible for an LCR RCM payment should not be longer than up to three years – the term of the Local RA requirement.

California Energy Storage Alliance (CESA), in addition to responses to the specific 7 Issues presented, also suggested that the WG should:

- consider pathways to maintain the load forecast adjustment process that is specific to an LSE and reflected in their pro rata share of the collective local RA requirements, and
- clarify and discuss the implications of the CPE buying all RA attributes if selected.

III. Description of Proposals

A. CalCCA Proposals

1. CalCCA Option #1

CalCCA's initial proposal, presented in its July 20, 2020, informal comments, advanced a CPE "must take" model. The model evolved as a result of the workshop and parties' comments, however, into a refined "Option #1" proposal presented in CalCCA's July 27, 2020, comments. CalCCA does not recommend adoption of this approach but prefers its "Option #2" described below.

Under the must-take model, the CPE would be bound to take any local RA attributes from preferred or energy storage resources shown by an LSE. The price would be determined using the following formula:

> Year 1: Use the median price from the last four quarters of Energy Division Power Charge Indifference Adjustment (PCIA) responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> Subsequent Years: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

This formulation removes the risk of market power influence by relying on the *median* CPE bid price rather than an *average* bid price. The median price is also unlikely to suggest pricing to future bidders, which an average price would do.

The number of MW shown by the LSE would be adjusted for effectiveness, using one of two methods. The first method would rely on published California Independent System Operator Corporation (CAISO) effectiveness factors, scaling a resource's effectiveness to the average effectiveness procured by the CPE in that specific local area. Because these factors do not fairly represent the value of resources, due to their focus on a limited subset of constraints, CalCCA did not favor this approach. The second method would rely on a yet-to-be determined methodology using data regarding peak contribution of particular technologies in specific local areas and data underlying the CAISO's identified storage need in its annual Local Capacity Technical Study. CalCCA pointed out, however, that developing these technology-specific methodologies would be time consuming and would, at best, provide only rough justice in determining the showing value.

CalCCA does not support adoption of Option #1 due to the complexity of developing reasonable effectiveness calculations. In addition, it is difficult to square a CPE "must-take" model with the directive in D.20-06-002 that shown resources must be "evaluated alongside bid resources."

2. CalCCA Option #2

CalCCA advances its Option #2 as the preferred methodology for the LCR RCM. Unlike Option #1, the CPE would not be bound to accept all shown resources but could reject them after considering their value "alongside bid resources." The "pre-determined price" calculation would be the same as Option #1:

> <u>Year 1:</u> Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> <u>Subsequent Years:</u> Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results

(prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

The only difference is that an LSE could choose to show its resources to the CPE for local credit at a price lower than the pre-determined price if desired.

The primary benefit of this approach, however, is administrative simplicity. Option #2 does not require further work to develop highly technical, technology-specific effectiveness values. Instead, it relies on the guidelines the CPE will use to evaluate bid resources. In other words, the CPE would apply the same methodology or considerations to *bid* and *shown local RA* resources in comparing their value.

Beyond these fundamental features, CalCCA addressed term and documentation of showings. Resources committed through a showing would have a three-year commitment where the term start date could be any year within the three-year forward compliance period. The showing (like bid) would be documented through a confirm under the Edison Electric Institute (EEI) Master Agreement.

3. CalCCA Proposal on Treatment of Existing Contracts

In essence, since preferred and storage resources are covered by the showing option, the legacy treatment for existing contracts identified by D.20-06-002 LCR RCM would only apply to existing fossil contracts. The Commission did not extend this same authority for an investor owned utility (IOU) to show fossil utility owned generation (UOG). As stated in D.20-06-002, existing fossil UOG would be required to bid into the CPE solicitation, and bid UOG would receive Cost Allocation Mechanism (CAM) treatment.[23]

CalCCA proposes that existing fossil contracts receive legacy treatment for five years from the implementation of the CPE. Legacy contracts will include only resources that are

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[23] D.20-06-002 at 48.

currently online and were contracted by an LSE on or before June 11, 2020 (the date D.20-06-002 was issued).

Summary of CalCCA Option #2 LCR RCM Recommendation	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	If selected, LSE will be paid the showing price (pre-determined price or below) without annual adjustment for effectiveness, like bid resources.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose (see §b. above.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or lower if the LSE showed at a lower price) for the shown resource.
Premium Granularity	Price is differentiated by local area or sub-local area, unless aggregation up is required to mask individual resource prices; not technology-specific prices.
Showing Term	LSE may show a resource for a term of up to three years, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show for the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing UOG "resources" do not qualify for a local showing.

B. SDG&E Proposal

SDG&E developed a proposal, included it in their July 20, 2020 comments, and presented the proposal at the July 27, 2020 workshop. SDG&E's proposal addressed resource applicability, local premium, effectiveness factors, duration, and cost-allocation.

On resource applicability, SDG&E noted that the LCR RCM would apply to only three categories of shown resources:

1. All energy storage;
2. All preferred resources; and
3. Existing contracts of existing fossil fuel resources.

On the local premium, SDG&E proposed that the CPE utilize the relevant PCIA System RA Market Price Benchmark (MPB) for its area, either north of path (NP)-15 or south of path (SP)-15 for the compliance year. SDG&E noted that the System RA MPB is typically available in November prior to the compliance year. SDG&E suggested consideration of the weighted average price of local resources that were contracted by the CPE for the compliance year. This means that the CPE must identify the specific cost related to RA capacity procured if it procured other attributes, such as flexible RA or energy tolling, which is necessary to ensure an apples-to-apples comparison. SDG&E also explored using the PCIA local MPB, however it was unclear how the CPE procurement of local resources would impact the PCIA local MPB calculation. Therefore, SDG&E recommended using prices relevant to CPE procurement. SDG&E also maintained that both values could be made publicly available in November after the CPE has finished its procurement along with the publication of the annual PCIA MPBs.

On effectiveness, SDG&E recommended that effectiveness factors should be guided by the CAISO and the annual Local Capacity Technical Study (LCTS). However, since that methodology may be too complex, SDG&E offered a simpler alternative until a more precise methodology can be adopted. SDG&E proposed that the effectiveness factors for all shown resources be calculated based on the percentage resulting from the local or sub-local area LCR divided by the total amount of capacity shown and CPE procured capacity. SDG&E provided the example that if the LCR is 100 MWs and 40 MWs were shown by LSEs, and 80 MWs were procured by the CPE, the percentage would be 100 MW / 120 MW, or 83.33 percent. LSEs that showed the total of 40 MWs would receive a credit of approximately 33.33 MWs.

In terms of duration, SDG&E proposed that the resources would be shown annually on a three-year rolling basis. SDG&E's proposal provided a process for how capacity would continue to be shown as well as offered in future years to the CPE.

For cost-allocation, SDG&E proposed that the premium associated with the shown local RA capacity would reduce the costs allocated to the LSE by the CPE for the procurement.

C. PG&E Presentation and Proposals

While PG&E did not present a full proposal at the July 27, 2020 workshop, PG&E's presentation included proposed guiding principles for the LCR RCM, detailed above in Section II and repeated here for convenience:

- The LCR RCM should:
  - Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;
  - Reflect the effectiveness of a resource at meeting reliability requirements to prevent "leaning" by LSEs;
  - Result in lower total costs to customers without sacrificing local area reliability; and
  - Not be reflective of market power and/or introduce gaming opportunities but may reflect a "premium" based on the additional cost of developing resources in local areas.

PG&E's presentation explained that PG&E had not identified a mechanism for developing a price that clearly met these proposed guiding principles. In attempting to establish an appropriate local price, PG&E considered two options: cost-based and market-based. PG&E discussed how each of these prices could be derived and outlined the drawbacks of each option.

PG&E also proposed that the LCR RCM premium should be as granular as possible in order to send the correct market signals.

PG&E further explained its view that any “workable” solution must be paired with a transparent and appropriate effectiveness adjustment and demonstration of reduction in total costs to customers. PG&E’s presentation provided information regarding the complexity and potential infeasibility of developing effectiveness adjustments using CAISO effectiveness factors, as well as other measures of effectiveness that could be explored.

PG&E concluded its presentation by stating that the LCR RCM should not result in an increase in total costs to customers. In other words, resources paid through this mechanism must be lower cost than its alternative, and the mechanism must not be game-able.

In addition, PG&E utilized the July 20, 2020, informal comments to provide its proposals with respect to treatment of existing contracts and existing owned resources. First, PG&E proposed that legacy treatment of existing contracts not be afforded to contracts for local resources that were procured outside of an LSE’s transmission access charge (TAC) area (e.g. a northern California LSE that procured a resource within a southern California LSE’s TAC), as those resources were not procured by the LSE to meet local RA requirements, but were likely procured to meet the LSE’s system RA requirements. PG&E also proposed that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired, prior to the date of issuance of D.19-02-022, March 4, 2019 (i.e. when the Commission affirmed its intent to adopt a centralized procurement framework for local RA resources and the possibility that LSEs may no longer have a procurement obligation for local RA). PG&E also proposed that legacy treatment not be applied for the full term of an existing contract or the life of an existing owned resource.

IV. Consensus and Non-Consensus Items

A. Matrix of Party Positions

As part of the WG process, the co-leads developed a matrix of party positions that covers key questions, including effectiveness, granularity, transparency, bidding issues, annual adjustments, the evaluation process, and shows where there is consensus and non-consensus among parties. The matrix was distributed to workshop participants on July 30, 2020, and parties provided edits to the matrix as part of informal comments submitted on August 3, 2020. The matrix has been updated to incorporate edits submitted on August 3, 2020, and is included in this Report as Appendix G.

B. Summary of Consensus and Non-Consensus Items for the 7 Issues

1. Cost-effectiveness

While some parties stated that the mechanism should not provide compensation if the resource does not provide value (CalPA) or does not reduce costs (PG&E), other parties argued that cost-effectiveness should not be in scope (CEDMC). Others raised feasibility of the mechanism if CAISO would need to provide information on effectiveness (SCE, SDG&E). Others argued that the CPE should produce multiple portfolios, akin to the transmission alternative portfolios the CAISO creates in the Transmission Planning Process, as a means to address cost-effectiveness (CESA).

With respect to how the mechanism should address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources, six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the topic should be within the scope of the mechanism and one party (CEDMC) stated that it should be outside of the scope of the mechanism.

PG&E and CESA expressed that a resource should demonstrate its effectiveness to receive compensation. CESA looks to have the assessment incorporate non-quantitative criteria, whereas PG&E looks to have only quantitative criteria used.

Six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the effectiveness adjustments could be determined by the CAISO through various mechanisms. The specific actions suggested by the parties varied, ranging from: adjustments to NQC values (PG&E), determination of effectiveness based on the portfolio options of the CPE (SCE), using the Local Capacity Technical Study (SDG&E), and developing a stakeholder process for determining the appropriate mechanism (CalCCA).

CalCCA's final proposal (Option #2) left the question to the CPE. The CPE is required to take effectiveness into account in selecting bids from its solicitations. Since CalCCA's proposal (Option #2) contemplates a comparison of shown preferred resources alongside bid resources, CalCCA submits that the CPE should apply the same criteria – whatever they may be – to both bid and shown resources.

2. Premium granularity

There was a broad spectrum of perspectives on premium granularity. Some parties argued that the premium should be dependent on the data available; for example, it could be sub-local area, local area, or TAC-wide area (SCE). Others argued for premiums for each resource technology type (CalPA) or by resource type, location, or operational characteristics (CEDMC), or based on location, including disadvantaged communities (DACs), GHG emissions reduction, and market power mitigation (CESA).

With respect to how granular the premium should be, three parties stated that the price premiums should be differentiated by local areas or sub-local areas (CalCCA, PG&E, and

SDG&E) [Note: Although SCE mentioned this as a possible option, it was not proposing differentiation by the TAC wide area.] unless a higher level of aggregation was required to mask the price of individual resource prices. SDG&E stated that it believed the complexity of developing individual premiums for the various types of resources in either sub-local areas or local areas makes the task infeasible.

One party stated that a series of premiums should be stacked to arrive at the final premium for a resource (e.g., closer-to-load, within a DAC, GHG emission reduction, and offers market power mitigation) (CESA). An additional party referenced a premium for a resource being located within a DAC (CEDMC).

3. Transparency of premium

Parties broadly supported as much transparency as possible, while still protecting market-sensitive information. Parties presented numerous ideas on how and when data should be presented. For instance, PG&E advocated for aggregating data upfront and making more detailed data available after sufficient time had passed. CalPA argued for posting the premiums to the service list and CESA argued that premiums should be made available by resource class. SDG&E argued that advance knowledge of the premium is not necessary since LSEs may have elected to show the resource if the offer is not selected by the CPE. The LSE does not lose any optionality in maximizing value for its customers.

CalCCA observed that its proposal would allow for full transparency of the predetermined price. Neither source of data required for the calculation -- the median bid price from the last CPE solicitation and the aggregated RA prices reported to Energy Division -- presents concerns regarding market sensitivity. The Energy Division prices are made public annually, and the median CPE price would reveal very little about the stratification of bids actually accepted by the CPE.

4. Bidding issues

On the issue of whether the mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation, both PG&E and CalCCA argued that the LSE would need to choose between voluntarily showing (for mechanism eligibility) and bidding / showing as part of the solicitation process. CESA argued that the LSE should not be precluded from also bidding and showing. SCE recommended that this topic be further discussed in workshops to address issues of gaming risk.

CalCCA also proposes a price formula for the pre-determined price. The "pre-determined price" calculation would be calculated as follows:

> Year 1: Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> Subsequent Years: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

An LSE could choose to show its preferred or energy storage resources to the CPE for local credit at a price up to the pre-determined price if desired.

5. Annual adjustments to local compensation

Parties had differing views on how frequently the mechanism should be adjusted. PG&E and SDG&E advocated that the premium should be updated annually to reflect the most recent CAISO Local Capacity Technical Study Report. CESA argued that an annual adjustment would not be necessary. Others argued that annual adjustments would ultimately depend on the details of the mechanism (SCE).

Because CalCCA proposes comparison of the shown resource alongside bid resources, as D.20-06-002 requires, CalCCA proposes no annual adjustment to the compensation. Bid resources are not adjusted annually for effectiveness but are paid as bid. In the same way, shown resources should be paid for the term of the showing at the pre-determined price (or below).

6. Bid evaluation process

On the question of how the CPE should incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources, there were several disparate ideas. SCE argued that the question should be addressed in CPE implementation as it relates to the bid selection process and bid selection criteria and how the CPE will fairly implement the least-cost-best-fit procurement criteria. CEDMC argued that both qualitative and quantitative criteria be considered, and preferred resources should be favored over fossil-fueled resources. CESA argued that the criteria should link to integrated-resource-plan-identified future long-term procurement needs in local or sub-local areas and adhere to the loading order and Senate Bill 1136 statutory requirements to facilitate the development of preferred, energy storage, and hybrid resources to the greatest extent possible.

7. Treatment of existing contracts

There were several proposals relating to the treatment of existing contracts that spanned a cutoff date for qualification, the period over which a contract should qualify, and whether UOG should qualify.

On the issue of a cutoff date, PG&E advocated that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired prior to the date of issuance of D.19-02-022, March 4, 2019. CalCCA argued that the mechanism should be applied to existing contracts entered into by an LSE on or before June 11, 2020. SCE stated that the cutoff date should be around the date when the Proposed Decision or the Final Decision was issued, i.e., either March 26, 2020 or June 11, 2020; while SCE is not opposed to PG&E's proposed March 4, 2019 cut-off date.

On the issue of the period over which a contract should qualify, SCE argued that it should be for up to a five-year term length. PG&E also stated that legacy treatment should not apply for the full term of the existing contract or owned resource. CalCCA recommends that the term be consistent with the terms sought for bid resources.

Lastly, on the issue of UOG, CalCCA argued that UOG should not be eligible, while PG&E advocated for eligibility for UOG.

V. Consensus and Non-Consensus Around Full LCR RCM Proposals

A. CalCCA's Proposal (Option #2)

CalCCA offered a complete proposal (Option #2) for the LCR RCM, summarized in their comments as follows:

Shown Resources Compared Alongside Bid Resources	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	No annual adjustment for effectiveness.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or the LSE's lower shown price) for the local RA premium.
Premium Granularity	Local area or sub-local area unless aggregation up is required to mask individual resource prices; no technology differentiation in pre-determined price.
Showing Term	LSE may show a resource for whatever term the CPE permits for its solicitations, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show its local RA attributes and receive the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing owned fossil resources do not qualify for a local showing.

Several parties expressed interest in this proposal, although there was not broad consensus reached from all parties involved in the WG. Both Calpine Corporation and AReM submitted informal comments questioning the concept of permitting bids outside of the auction process and suggesting that there should be "full flexibility to specify the prices at which shown resources will be compared to bid resources" in the CPE's auction to provide LSEs "incentives to offer competitively to ensure that their resources are selected over offered resources." AReM observed that all options for a compensation mechanism have risks for market power and gaming

and questioned "if the limited potential benefits warrant moving forward with any compensation mechanism."

PG&E submitted comments in reply to CalCCA's proposal (Option #2) stating that PG&E did not find that the proposal clearly meets all of the objectives in D.20-06-002; however, PG&E believes it is reasonable and the only workable solution that has been put forth by the WG that clearly meets the objective of allowing LSEs to retain the system and flexible RA attributes and receive compensation for the local RA attribute under the hybrid procurement framework. If the Commission is willing to consider this proposal, PG&E believes that (i) all LSEs, including IOUs, should be able to avail themselves of the LCR RCM in the same manner (which requires the Commission to revisit IOU bidding requirements in D.20-06-002 in a new track of the RA proceeding or identify another venue to evaluate the bidding requirements for IOUs to participate in the LCR RCM proposed by CalCCA in Option #2), and (ii) LSEs should continue to be afforded the "voluntarily shown" option, without compensation under the LCR RCM, should LSEs want to retain the system/flexible RA products for use toward its LSE-specific system and flexible RA requirements.

SCE also submitted comments in reply to CalCCA's proposal (Option #2) stating that there are merits to the proposal, and it should be further explored. SCE recommended a few clarifications to the proposal, including (i) if a shown resource is selected by the CPE during the solicitation, then the LSE should be paid its offer price for the shown resource, not the pre-determined premium, and (ii) the option of showing a local resource without direct compensation should be retained and made available to all LSEs.

B. SDG&E's Proposal

As described in Section III.B, SDG&E also provided a full proposal on the LCR RCM. PG&E submitted comments on SDG&E's proposal expressing concerns that the proposed methodology does not appropriately addresses cost effectiveness concerns. PG&E believes that it may overestimate voluntarily shown resources, which may result in customers paying for resources that do not provide any ratepayer value or any local area reliability benefits to the system. Additionally, PG&E has concerns with SDG&E's proposal on local premium price, as this methodology is similar to the financial crediting mechanism proposed by CalCCA in Rulemaking 17-09-020 that was rejected by the Commission and specifically excluded from the scope of consideration in this Track.

<u>Appendices</u>

Appendix A: July 6, 2020 Service Email

Appendix B: July 20, 2020 Informal Comments

Appendix C: July 27, 2020 Working Group Workshop Presentations

Appendix D: August 3, 2020 Informal Comments

Appendix E: August 17, 2020 Informal Reply Comments

Appendix F: August 26, 2020 Informal Comments on Draft Report

Appendix G: Final Matrix of Party Positions

APPENDIX A

JULY 6, 2020 SERVICE EMAIL

Subject: [R.17-09-020 and R.19-11-009] Co-Leads and Schedule for Working Group on LCR Compensation Mechanism and Treatment of Existing Contracts

Date: Monday, July 6, 2020 at 1:23:13 PM Pacific Daylight Time

From: Leung, Michael

Resending to the service list, due to clerical error on the CalCCA contact.
Melissa Brandt (mbrandt@ebce.org) is the correct contact, not Todd Edmister.

~

To R.17-09-020 and R.19-11-009 Service Lists:

This email provides notice of working group co-leads and a schedule for the working group authorized in Decision (D.) 20-06-002 to develop and assess proposals regarding (a) a local capacity requirement reduction compensation mechanism and (b) treatment of existing local resource adequacy (RA) contracts in light of the hybrid central procurement structure adopted by the California Public Utilities Commission (Commission) for local RA procurement beginning in 2021. In addition, this email seeks informal written comments from parties on the issues outlined in Ordering Paragraphs 5 and 6 of D.20-06-002 by July 20, 2020.

<u>Background</u>

In D.20-06-002, the Commission adopted a hybrid central procurement structure for local RA procurement beginning in 2021. As stated in D.20-06-002, in order to compensate load-serving entities (LSEs) for shown local preferred and energy storage resources, "[t]he Commission will develop an LCR reduction compensation mechanism, if details can be assessed and developed." The LCR reduction mechanism will be a "financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value." "The Commission is not open to considering a one-for-one credit, [the California Community Choice Association's (CalCCA)] proposed financial credit mechanism, or a credit mechanism for fossil fuel resources (other than potentially for existing [ ] contracts)."

To facilitate the assessment and development of such a mechanism, the Commission directed a working group and also ordered that this working group consider and submit a proposal on the treatment of existing contracts. The Commission required that the working group be co-led by CalCCA and either Pacific Gas and Electric Company (PG&E) or Southern California Edison Company and that a working group report on consensus and non-consensus items must be filed in R.19-11-009 by September 1, 2020. Notably, D.20-06-002 requires that any proposal to be offered for consideration must be presented through the working group report.

<u>Working Group Co-Leads</u>

The working group co-leads for the issues specified above are CalCCA and PG&E.

Please include the following CalCCA and PG&E representatives on all communications related to this working group:

CalCCA:

Evelyn Kahl – evelyn@cal-cca.org
CC Song – ccsong@cleanpoweralliance.com
Deb Emerson – demerson@sonomacleanpower.org
Melissa Brandt – mbrandt@ebce.org

PG&E:

Erica Brown – Erica.Brown@pge.com
Rhett Kikuyama – Rhett.Kikuyama@pge.com
Lisa Wan – Lisa.Wan@pge.com
Noelle Formosa - Noelle.formosa@pge.com

Working Group Schedule

Given the expedited timeframe for preparation of the working group report, as acknowledged in D.20-06-002, CalCCA and PG&E have developed the following expedited schedule to facilitate assessment and discussion of proposals. As noted below, please notify the Co-Leads by July 20, 2020 if your organization has an intent to present a proposal at the workshop by sending an email to the email addresses listed under "Working Group Co-Leads" above. Additional details regarding the workshop will be communicated to the service lists at a later date.

Event	Due Date
Notice to Service List of Co-Leads and Schedule/Request for Informal Comments	July 6, 2020
Parties Provide Informal Comments to Service Lists and Notify Co-Leads of Intent to Present at Workshop	July 20, 2020
Workshop on Parties' Proposals	July 27, 2020 (tentative)
Parties Provide Informal Comments on Workshop to Co-Leads	August 3, 2020 (tentative)
Co-Leads File Working Group Report	September 1, 2020

Request for informal written comments on issues outlined on pages 43-45 and in Ordering Paragraphs 5 and 6 of D.20-06-002 - Due July 20, 2020

In order to facilitate development of proposals in advance of the workshop scheduled for July 27, 2020, CalCCA and PG&E request informal written comments from parties on the following issues by July 20, 2020. Please transmit any informal comments to the service lists in R.17-09-020 and R.19-11-009.

1. Page 43: How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?

2. Page 44 & Ordering Paragraph 5:

a. How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);

b. How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

c. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process; and

d. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

3. Pages 44-45: How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?

4. Ordering Paragraph 6: In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.

Please contact Lisa Wan at lisa.wan@pge.com if you have any questions.

On behalf of Noelle R. Formosa,

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Case Coordinator
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San Francisco, CA 94105
415-973-2766 | M7L7@PGE.com

APPENDIX B

JULY 20, 2020 INFORMAL COMMENTS

INFORMAL COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS ON LCR REDUCTION COMPENSATION MECHANISM (R.19-11-009)

The Alliance for Retail Energy Markets ("AReM")[1] submits these informal comments regarding the Local Capacity Requirements ("LCR") Reduction Compensation Mechanism, as requested by e-mail on July 6, 2020 by the Co-Leads of the Working Group directed in Ordering Paragraph 5 of Decision ("D.") 20-06-002 implementing the Central Procurement Entity ("CPE"). Consideration of the LCR Reduction Compensation Mechanism has been incorporated into the scope of Track 3A in Rulemaking 19-11-009.[2] As noted in the July 6th e-mail, this Working Group will also address the treatment of existing contracts as directed in Ordering Paragraph 6 of D.20-06-002.

AReM has no specific proposal to submit for consideration at this time on the LCR Reduction Compensation Mechanism or the treatment of existing contracts. With respect to the requirement that the Co-Leads for this Working Group assess and develop a LCR Reduction Compensation Mechanism, AReM believes that there are many details that need to be discussed to determine if such a mechanism is necessary and feasible, particularly to gain a better understanding of why "shown" resources – those owned or controlled by Load Serving Entities ("LSEs") who opt to show the resource to the CPE in order to reduce the amount that the CPE must procure – should be eligible for a payment outside of the auction process. AReM looks forward to working with the Co-Leads on this issue. AReM requests that the Co-Leads focus on

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[1] AReM is a California non-profit mutual benefit corporation formed by electric service providers that are active in the California's direct access market. This filing represents the position of AReM, but not necessarily that of a particular member or any affiliates of its members with respect to the issues addressed herein.

[2] *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling,* R.19-11-009, July 7, 2020, Track 3.A, Issue 2, p. 3.

the following principles in the evaluation of the need and structure for any such Compensation Mechanism:

1. No CPE Overprocurement: The ability for a LSE to receive a LCR Reduction Compensation Mechanism payment from the CPE must not result in overprocurement by the CPE with the overprocurement costs spread among all LSEs.
2. Cost Causation: The customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; they should not spread those costs to other LSEs or to the customers of other LSEs.
3. Premiums Paid for Shown Resources Must Be Aligned with the Auction: To the extent that payments for shown resources are determined to be warranted, LSEs with such resource types that are worth a premium to the CPE should be eligible for compensation up to that premium. That is, if the CPE auction awards a higher Resource Adequacy ("RA") price to energy storage, any LSE-shown resource that is energy storage should be eligible for the LCR Reduction Compensation Mechanism premium that does not exceed the premium paid for such resources in the auction
4. Payment Length for Shown Resources Must Be Aligned with the Local RA Requirement: The number of years of compensation for which a LSE is eligible for a LCR Reduction Compensation Mechanism payment should be for no longer than up to three years – the term of the Local RA requirement.

Submitted on behalf of AReM by:
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July 20, 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.	R.17-09-020

CALIFORNIA COMMUNITY CHOICE ASSOCIATION INFORMAL COMMENTS ON THE LOCAL CAPACITY REQUIREMENT COMPENSATION MECHANISM

Evelyn Kahl, General Counsel
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regulatory@cal-cca.org

July 20, 2020

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**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
INFORMAL COMMENTS ON LOCAL CAPACITY REQUIREMENT
COMPENSATION MECHANISM**

The California Community Choice Association (CalCCA)[1] submits these informal comments on the issues identified in Decision (D.) 20-06-002 for resolution in the Resource Adequacy (RA) Central Procurement Entity (CPE) Working Group (WG).

I. INTRODUCTION

The Commission recognized in D.20-06-002 that a "financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas."[2] It tasked the CPE WG with further developing this mechanism for implementation within certain parameters. The parameters center primarily on mitigating the influence of "market power inflated premiums" and reflecting the effectiveness of a resource in addressing local constraints in the compensation mechanism. The

[1] California Community Choice Association represents the interests of 20 operational 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 José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

[2] D.20-06-002 at 41.

Commission further provided a list of questions to be answered by the CPE WG. These comments explore these issues and present a framework for discussion with stakeholders.

II. PROPOSAL

A. Accounting for Local RA Resource Effectiveness

Decision 20-06-002 requires the LCR Reduction Mechanism compensate LSEs for shown local RA preferred resources only "to the extent they provide ratepayer value."[3] Consequently, it requires the Working Group to address "the resource cost effectiveness concerns [] (including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources)."[4] Subject to concerns regarding feasibility and consistency, CalCCA generally supports the principle that LSEs should receive credit for shown local RA resources in proportion to the resources' relative usefulness in meeting California Independent System Operator (CAISO) needs.

As an initial matter, CalCCA questions the premise that preferred resources shown under the LCR Compensation Mechanism can be "evaluated alongside bid resources" as D.20-06-002 suggests. The Commission has required a "pre-determined" price for shown resources, which gets set *prior to* the solicitation.[5] If the goal is to consider the value of the showing relative to the selected portfolio, an *ex post* price would be necessary to ensure that the shown resources were not priced higher than the bid prices – an approach the Commission expressly rejected.[6] Moreover, in providing the showing option, the Commission has acknowledged the need to balance the incremental pricing precision that *might* arise if all resources were priced in the bid solicitation process with the need for development incentives for individual LSEs with. Instead

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3 *Id.* at 43.
4 *Ibid.*
5 D.20-06-002 at 42.
6 *Ibid.*

of considering the shown resources "alongside" the bid resources, the shown resources should form the baseline for the CPE portfolio completed through the solicitation process.

Increasing the challenge of meeting the Commission's expectations, D.20-06-002 tasked the Working Group with an issue that the Commission itself has not tackled in its local RA program: differentiating effectiveness among local RA resources for purposes of valuing the local RA contribution. Today, the only clear information an LSE has about the relative reliability value of a particular local RA resource derives from the Net Qualifying Capacity (NQC) and Effective Load Carrying Capability (ELCC) signals. While the CAISO annual Local Capacity Technical Study discusses effectiveness, neither the Commission nor the CAISO has translated the relative local effectiveness of a resource into an implementable metric. To the contrary, the Commission's own counting conventions value all local RA MW equally.

Not even the CAISO – the one who ultimately determines effectiveness of the local RA portfolio – can assign a single effectiveness factor to any resource. The CAISO explained the challenge in its comments on the RA-CPE Settlement:

> As noted above, effectiveness, used correctly, measures the impact a specific resource has on the most stringent contingency in a local capacity area or sub-area. As the CAISO noted in its annual Local Capacity Technical Study, a single resource may impact multiple local areas and/or subareas. Additionally, the effectiveness factor is a measure of the resource's impact on the most stringent contingency. In some instances, the second most stringent contingency may only be slightly less severe than the most stringent but the same resource may be substantially less effective at addressing the second most stringent contingency.[7]

For these reasons, the CAISO stressed that the effectiveness factors it identifies "are not definitive metrics that guarantee local reliability."[8] Critically, the CAISO concluded:

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[7] R.17-09-020, *Reply Comments of the California Independent System Operator Corporation*, Oct. 15, 2019, at 5.

[8] *Id.* at 5-6.

> Alternatives to the current methodology of one-for-one MW accounting for local capacity resources to include a more granular effectiveness assessment would add exponential levels of complexity to the central procurement process and would be unlikely to impact overall reliability in local capacity areas.[9]

The practical effect of the issue raised by CAISO is that even if a new local resource were more effective than existing resources at addressing "the most stringent contingency in a local capacity area or sub-area" it might be less effective at addressing the next several most stringent contingencies. Therefore, its presence might not result in an overall reduction in the need for local capacity resources in the local area, or an increase in overall reliability. This Working Group is unlikely to solve a problem in three months that neither the Commission nor the CAISO has solved over the course of years.

In considering solutions, CalCCA observes that the preferred resource showing is not the only process affected by effectiveness. Decision 20-06-002 requires the CPE to include "local effectiveness factors," in its resource selection criteria.[10] It is not clear how the criterion would be applied, nor whether or how it would affect valuation. The methodology for determining the relative value of resources in a local area, regardless of methodology, should be consistently and transparently applied in both the CPE solicitation and the showing process.

Despite these concerns, CalCCA has begun to consider alternative approaches to ensuring "ratepayer value" and preventing "leaning." Exploring metrics for resources with use limitations, including battery storage, hydro, and fossil generation with limited starts or air quality restrictions, offers the most promise. Any metric of the "effectiveness" of a resource at meeting the local capacity area reliability requirements that could be derived would be incorporated not through a price reduction, but into a technology-specific modification of the number of MW

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9 *Id.* at 6.

10 D.20-06-002, Ordering Paragraph 14.b at 95.

receiving the premium for each local capacity area or sub-area. While CalCCA does not offer a specific proposal in these comments, the CAISO's 2021 Local Capacity Technical Report[11] offers an example of a potential starting point for a methodology to estimate overall effectiveness of battery storage that would be limited by charging restrictions. Table 3.1-3 "includes estimated characteristics (MW, MWh, discharge duration) required from battery storage technology in order to seamlessly integrate in each local area and sub-area."[12] The Pmax field identifies the maximum amount of storage that can be used to address the local capacity need, while the Energy divided by the Pmax identifies the duration of storage needed. These factors could be incorporated into an approach for identifying the MW credit to apply for storage resources in each local capacity area or sub-area, though a more detailed exploration would be required to pursue this type of approach.[13]

CalCCA recommends that effectiveness be considered beyond this Working Group considering its broader relevance. Because the CAISO is the only stakeholder with the ability to assess overall portfolio effectiveness, the CAISO should lead a stakeholder process to develop factors that could be used by both the CPE in its selection criteria and to value shown resources. Ultimately, usefulness must be judged by the CAISO – the expert on local reliability -- and the Commission should look to the CAISO for mechanisms to compare resource effectiveness at meeting the local capacity area reliability requirements.

B. Calculation of the LCR Reduction Premium

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11 *2021 Local Capacity Technical Study* http://www.caiso.com/Documents/Final2021LocalCapacityTechnicalReport.pdf

12 *Id.* at 27-28.

13 For example, the CAISO's LCR technical studies take into consideration existing local resources and, in some cases, such as for the OCEI project in the Oakland sub-area, planned resources. These resources thus may have greater effectiveness at meeting the local capacity requirements than the values identified by the CAISO in the LCR technical studies for incremental resources.

The Commission in D.20-06-002 set three boundaries for designing the LCR compensation mechanism:

a. The premium must be "pre-determined";[14]

b. The premium must reflect "the cost to ratepayers of selecting the shown resources over purchasing bid resources";[15]

c. The premium must mitigate the risk that it will reflect prices charged by sellers exercising market power, noting that "it may be cost-based" and "compensate LSEs for additional costs of procuring resources close to load" to prevent this result.[16]

In addition, the Commission posed specific questions to the Working Group, seeking recommendations on the level of granularity required for the premium and transparency of the premium value.

CalCCA's proposal aims to meet these objectives, to the extent they can be met. The amount of premium would be pre-determined, rather than determined ex post, recognizing that the Commission rejected CalCCA's ex post premium proposal.[17] The pre-determined price will benefit showing LSEs to ensure they have knowledge of the perceived resource value before deciding whether to bid or show their resources. The premium would also, as directed by the Commission, mitigate the risk of "market-power inflated premiums." CalCCA's proposal mitigates this risk by relying on a median referent price, rather than average prices as CalCCA initially proposed,[18] since a median price is unaffected by high outliers in a price distribution. Finally, the CalCCA proposal addresses transparency by relying on information that is (or will become) public through Energy Division reports.

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14 *Id.* at 42.
15 *Ibid.*
16 *Ibid.*
17 D.20-06-002 at 42.
18 *Id.* at 40.

The premium would be calculated as follows:

<u>Year 1</u>: Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system price from local RA price and multiply by effective MW.

<u>Subsequent Years</u>: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW.

Price premiums would be differentiated by local areas, including the disaggregated "PG&E Other" areas, unless a higher level of aggregation were required to mask the price of individual resource prices.

CalCCA considered a cost-based approach, which D.20-06-002 suggested as an option. There are no known objective sources, however, for data to establish cost-based premiums. In addition, CalCCA submits that its proposed market-based approach best serves both LSEs and ratepayers for several reasons.

- **Simpler than a Cost-Based Approach.** The cost of any project is a function of many factors, making it nearly impossible to find comparable projects to isolate the "local" value.
- **More Accurate Than a Cost-Based Approach.** Using cost-based premiums would require unbundling a local RA premium from a bundle of attributes, including energy, system RA. and, potentially, RPS attributes.
There is simply no way to know which portion of the value stream lies with local RA.
- **Market Based Approach More Effectively Protects Ratepayers.** Using a cost-based approach would harm ratepayers if the resource cost were higher than the prices the RA-CPE otherwise could have received in the market.
- **Market Based Approach Ensures Transparency**. Cost-based premiums would not be transparent.

And, as discussed above, using a transparent, median, recorded local RA price best mitigates the risk "market power inflated premiums," eliminating the need for a cost-based solution.

C. Other Considerations

Although not identified for Working Group consideration by D.20-06-002, CalCCA offers two recommendations on other LCR Compensation Mechanism Issues. First, the Commission should clarify the term of any showing. CalCCA recommends that resources be committed, through the solicitation or showing, for a three-year term. The start year for the term must be within the three-year forward compliance period. Second, a showing, like a successful bid, should be documented through a confirm under the EEI Master Agreement. The commitment for showing should have the same weight as a bid resource commitment to ensure the resource remains available for RA-CPE reliance.

D. LSE Elections

Decision 20-06-002 asked for comments on whether an LSE would need to choose between showing or participating in the solicitation. CalCCA recommends that the LSE be required to choose between these options. Showing will precede the solicitation, subject to a pre-determined premium value -- so an LSE will need to make the decision at that time. It should not be permitted to game a strategy between the two options, e.g., choosing to show only if its bid is rejected.

E. Treatment of Existing Contracts

Decision 20-06-002 requires the Working Group to submit a proposal on the treatment of existing contracts.[19] It provides that the proposal "provides which may include consideration of whether any proposed LCR reduction compensation mechanism should be applied to existing contracts." It suggests that the solution should be limited, however, to resources currently online "absent compelling information" provided by the Working Group. [20]

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[19] D.20-06-002 at 46.

[20] *Ibid.*

CalCCA supports the Commission's direction. The same LCR Compensation Mechanism adopted for preferred resources should be applied to existing contracts entered into by an LSE on or before June 11, 2020. This mechanism should not be applied to utility owned generation, which will be required to bid into the RA CPE solicitation.

III. CONCLUSION

CalCCA looks forward to further exploring these and other proposals with stakeholders at the July 27, 2020, CPE WG workshop.

Respectfully submitted,

Evelyn Kahl

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General Counsel to the
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July 20, 2020

July 20, 2020

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cc: R.19-11-009 Service List

Subject: CESA's informal comments for the Central Buyer Working Group

Re: CESA's Informal Comments on the Working Group on LCR Compensation Mechanism and Treatment of Existing Contracts

Dear Working Group Co-Leads:

The California Energy Storage Alliance (CESA) appreciates the opportunity to participate in the Working Group and offers our informal comments to the questions posed in Decision (D.) 20-06-002, issued by the California Public Utilities Commission (Commission) on June 17, 2020. In addition to our responses, CESA offers a high-level comment on some key clarifications needed to establish a common understanding of the new central buyer framework for Local Resource Adequacy (RA) procurement, which has raised a number of questions and created uncertainty from industry on the implication of this decision on existing contracts as well as on future resource procurement. Our informal comments can be summarized as follows:

- To balance cost-effectiveness and resource effectiveness considerations, the Central Procurement Entity (CPE) Request for Offers (RFO) should identify multiple portfolios of bid and shown resources.
- The Local Capacity Requirements (LCR) Reduction Compensation Mechanism should consider premiums related to being closer-to-load, siting in disadvantaged communities (DACs), greenhouse gas (GHG) emissions reduction, and market power mitigation.
- To balance transparency with confidentiality of market-sensitive information, the local premium for shown resources should be calculated based on base

assumptions of a resource class that can be customizable to reflect the specific project value and benefits.

- The compensation mechanism should not preclude an LSE from both bidding or showing a resource since the effectiveness of many resources will not be able to be ascertained until an actual resource portfolio is constructed and aggregated from the CPE RFO bids.

- Unless substantiated otherwise, a year-to-year adjustment to the local compensation mechanism should not be established and may not be needed.

- The CPE RFO evaluation criteria should mirror the premium factors in the local compensation mechanism, link to IRP-identified future long-term procurement needs in local or sub-local areas, and adhere to the loading order and SB 1136 statutory requirements to the greatest extent possible.

- The working group should consider pathways to maintain the load forecast adjustment process that is specific to an LSE and reflected in their pro rata share of the collective Local RA requirements.

- The working group should clarify and discuss the implications of the CPE buying all RA attributes if selected.

Responses

1. **How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?**

   CESA is unclear on how the CPE framework will address the aforementioned concerns while balancing cost effectiveness. For example, it is unclear if the CPE will use local effectiveness and use limitations as the binding, initial screening criteria for evaluating resources bid into the RFO and then consider resource costs and benefits, or if the bids will be assessed comprehensively for effectiveness, limitations, costs, and benefits. If the former, CESA is concerned that the CPE RFO will over-select a resource portfolio that includes a substantial portion of existing fossil generation. Rather, CESA favors an approach where the CPE RFO considers identifying multiple portfolios of bid and shown resources that, on one end, considers effectiveness as the binding, initial screening criteria and, on the other end, more heavily considers preferred attributes while ensuring effectiveness. Several portfolios could be presented in between these extremes to identify the least-cost best-fit resources that meet reliability needs while advancing decarbonization objectives. This approach would be akin to the transmission alternative portfolios created by the California Independent System Operator (CAISO) in their Transmission Planning Process (TPP).

2. **How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas)?**

CESA generally supports granularity to the premium of the LCR reduction compensation mechanism and proposes the following premiums for consideration in the working group:

- **Closer-to-load premium:** Percentage premium should be considered to recognize the value-add of RA resources that are located closer to load, thus minimizing line losses and offering direct customer or community benefits. Some line loss factor for resources connected at different service levels could be established to support distribution-connected and customer-sited Local RA preferred or storage resources that are shown.

- **DAC premium:** For local preferred or storage resources in DAC areas as defined, some administratively-set percentage premium could be applied to such shown resources. This could be reflected in some administratively-set calculation of the pollution burden faced by DAC customers, particularly from local criteria pollutants, which have yet to be adequately reflected in a systematic fashion in the IRP or RA settings.

- **GHG emissions reduction premium:** For local preferred or storage resources that are already being modeled as needed in the IRP to reduce GHG emissions and local pollutants, the GHG mitigation price from the IRP models for the applicable planning year should be factored into the premium applied to shown resources.

- **Market power mitigation premium:** For certain constrained areas with major market power issues, some premium could be applied to new local preferred or storage resources that mitigate these market power impacts with the addition of new supply resources. This premium would recognize the value provided by new-build resources that face disadvantages in the CPE RFO (compared to existing, already built and depreciated resources) due to the cost of new entry of resources.

3. **How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices.**

CESA agrees that premiums should protect market-sensitive information. One way to balance transparency with the need for confidentiality would be to consider base class-specific premiums that are broadly applicable to all resources within that class. For example, energy storage resources as an asset class may have common premiums that are broadly applicable to all project types, with differences depending on whether they are hybridized with generation, interconnected in front of the meter or behind the meter, or reflect a technology with different performance capabilities. Even with these base assumptions of a resource class, however, the premiums should be customizable to reflect the specific project value and benefits. A one-size-fits-all premium may undercut the incremental value-add of certain projects. CESA looks forward to discussing whether and how any customizable premium could be considered.

4. **Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process.**

The compensation mechanism should not preclude an LSE from both bidding or showing a resource. CESA agrees that overlaying both of these mechanisms is complex and not preferable, but the compensation mechanism and bid evaluation criteria should generally mirror each other. As CESA understands it, the major difference between bidding or showing a resource depends on the resource effectiveness in meeting the local need, which determines whether a resource warrants 1-for-1 crediting. Even with resource effectiveness factors published in the CAISO's Local Capacity Technical Report, the effectiveness of many resources will not be able to be ascertained until an actual resource portfolio is constructed and aggregated from the CPE RFO bids. For example, in certain constrained local areas, the resource effectiveness of energy storage will not be known in advance of the RFO until all eligible resources are submitted as bids in the RFO and sufficient generation is made available in the resulting portfolio. A generation-heavy portfolio from one LSE may then address the charging limitations of a storage-heavy portfolio from another LSE. Precluding an LSE from both bidding and showing options in order to claim the compensation mechanism would thus be unreasonable and not lead to the identification of the least-cost best-fit portfolio, as directed by D.20-06-002.

5. **How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.**

Unless substantiated otherwise, CESA opposes a year-to-year adjustment to the local compensation mechanism. None of CESA's proposed premiums suggested for inclusion in the LCR reduction compensation mechanism are subject to change over time. Meanwhile, resource effectiveness considerations are already factored in the CPE RFO, which are run on a three-year forward basis such that any changes in resource effectiveness factors would determine whether a local resource is selected or just credited as a shown resource. CESA sees no need to add an additional changing variable in the local compensation mechanism, which only adds to the regulatory uncertainty of the Local RA value and compensation for a particular resource. Already, the CPE structure has introduced a significant level of uncertainty where new resources are not guaranteed to be selected as part of a least-cost best-fit portfolio in the long term.

6. **How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?**

CESA believes that many of the premiums added to the LCR reduction compensation mechanism should be mirrored in the bid evaluation criteria for the CPE RFO. CESA generally supports the selection criteria included in D.20-06-002 at 52-53 and adds further perspective on how the criteria could be enhanced:

- **Future needs in local and sub-local areas:** This is the criterion where CESA sees potential to link IRP-identified future long-term procurement needs with the short-term forward procurement of the RA Program. Depending on the scope and modeling conducted in the new IRP proceeding (R.20-05-003), CESA believes that this is an area where the specific GHG adder price identified in the Reference System Portfolio could be added to the evaluation of existing fossil generation versus new preferred resources. If the IRP is able to conduct such locational assessments, the GHG mitigation price identified in the IRP could be incorporated here as a benefit for preferred or storage resources. In the interim, the system-level GHG mitigation price for three years ahead could be used in the RFO in alignment with the three-year forward requirements for Local RA.

- **Local effectiveness factors:** CESA seeks clarification from the CAISO in terms of how energy durations and charging limitations would be assessed in the RFO and translated to a Local RA value, specifically as it applies to storage. For example, this criterion appears to introduce a deviation from the current RA counting conventions for storage where long-duration storage or storage hybridized with generation may have Local RA capacity values and commensurate compensation that is not limited to the four-hour capacity convention for storage resources.

- **Resource costs:** This criterion is straightforward, so CESA has no further comment at this time.

- **Operational characteristics of the resources:** It is unclear how these characteristics will be reflected in the RFO in an administratively efficient fashion. Operational assumptions as identified in the IRP and as required under RA availability and performance obligations should instead be used to consider how resources may impact GHG emissions, reliability, etc.

- **Location of the facility:** As noted above, a premium should be attributed to preferred or storage resources that are located in disadvantaged communities.

- **Costs of potential alternatives:** This criterion is straightforward, so CESA has no further comment at this time.

- **GHG adders:** If the GHG mitigation benefits for future needs in local and sub-local areas (as noted above) is incorporated, this criterion may be duplicative. If not, then GHG adders should be added to the

- **Energy-use limitations:** To the degree that this criterion is duplicative of local effectiveness factors, particularly for energy storage resources, consideration of energy-use limitations may not be needed. Even for all other resources, energy-use limitations may be addressed in Track 3 proposals and should generally be reflected in the RA requirements for resources. Already, imports and certain demand response resources (*i.e.*, DRAM) have some level of energy requirements that may be duplicative of this criterion.

- **Procurement of preferred resources and energy storage:** D.20-06-002 cites previous statutory language that makes clear that the loading order should be adhered to. Statutory changes pursuant to Senate Bill (SB) 1136 also sets this preference for clean RA resources. Some administratively-set "tolerance band" for bid prices (*e.g.*, 10%) could be established to encourage the selection of preferred or storage resources, even if the net prices exceed existing fossil generation by a "minor" amount.

Given the above, CESA requests that the working group also come to agreement on the specific evaluation criteria to be used in the CPE RFO. A stakeholder process to assess and develop these criteria will play an important role in advancing the intent of the Commission decision to ensure local reliability but also to advance preferred resources in line with the state's policy goals. Otherwise, CESA fears that the CPE RFO will be a black box that makes it unclear to stakeholders on how and why certain resources were selected. Notably, one area of ambiguity in the decision is around how dispatch rights to the CPE, even as an optional term, will factor into bid selection.

7. **In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.**

   CESA does not have a response at this time but may offer comments in the future.

<u>**General Comments & Questions**</u>

D.20-06-002 presents a number of substantial changes to the Local RA procurement paradigm that has raised a number of questions among industry in terms of how this would impact existing contracts and future procurement. While the working group is tasked with developing an LCR reduction compensation mechanism, stakeholders may also benefit from level setting and establishing a common understanding of the CPE structure as a threshold matter. This exercise may streamline working group discussions.

1. **The working group should consider pathways to maintain the load forecast adjustment process that is specific to an LSE and reflected in their pro rata share of the collective Local RA requirements.**

   D.20-06-002 at 27 explained that new local demand-side resources that are not integrated in the CAISO market would have its load impacts flow into the California Energy Commission (CEC) load forecast and thus reduce the overall local needs. CESA finds this problematic and significantly dilutes (if not eliminates) the incentive for any given LSE to develop load-modifying programs. Prior to this decision, CESA understands that the load forecast adjustment process was specific to an LSE. Instead of the decision's approach discussed in "theory", CESA recommends that the working consider how LSE-specific load adjustment processes can be maintained, which would in effect reduce the pro rata share of load that any given LSE would be subject to for the overall Local RA requirements. This is reasonable given that LSE-specific load forecasting is already done today and is not expected to change.

2. **The working group should clarify and discuss the implications of the CPE buying all RA attributes if selected.**

As CESA understands it, based on the 2019 working group report, resources that are bid and selected in the CPE RFO will count on a 1-for-1 basis to the collective Local RA requirements and would also count fully toward the system- or TAC-wide System and Flexible RA value for all applicable LSEs. While local attributes are the most valuable based on reported average prices, the purchase of all RA attributes by the CPE raises a number of questions and concerns. First, System and Flexible RA requirements are only needed on a one-year forward basis at this time, so it is unclear whether the CPE would be purchasing all RA attributes on a similar three-year forward basis as done for Local RA. Second, this would raise concerns about whether and how an LSE will be fully credited for procured for the purpose of System and Flexible RA. Clarifications on the impact to System and Flexible RA in the working group would be helpful.

Conclusion

CESA appreciates the opportunity to provide these informal comments and hope these responses are helpful. Please do not hesitate to reach out if you have any follow up questions or would like to discuss further.

Sincerely,

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California Efficiency + Demand Management Council Informal Comments on Issues Outlined on Pages 43-45 and in Ordering Paragraphs 5 and 6 of D.20-06-002

Introduction:

The California Efficiency + Demand Management Council (Council) respectfully submits these informal written comments on issues outlined on pages 43-45 and in Ordering Paragraphs 5 and 6 of Decision (D.) 20-06-002 (Decision on Central Procurement of the Resource Adequacy Program), issued in Rulemaking (R.) 17-09-020 (Resource Adequacy (RA)) on June 11, 2020.[1] Interested parties were requested to provide informal written comments on various issues outlined in D.20-06-002.

Background:

The Council is a statewide trade association of non-utility businesses that provide energy efficiency, demand response, and data analytics services and products in California.[2] Our member companies employ many thousands of Californians throughout the state. They include demand response (DR) and grid services technology providers, implementation and evaluation experts, energy service companies, engineering and architecture firms, contractors, financing experts, workforce training entities, and manufacturers of energy efficiency (EE) products and equipment. The Council's mission is to support appropriate EE and DR policies, programs, and technologies to create sustainable jobs, long-term economic growth, stable and reasonably priced energy infrastructures, and environmental improvement.

Informal Written Comments:

1. **How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?**

Cost effectiveness of local resources should not be within the scope of the mechanism. It seems reasonable to expect that procurement of local resources by load serving entities (LSEs) would be done through competitive solicitations with the optimal products selected, so procured local resources should be cost-effective by definition. Also, adding a cost-effectiveness threshold to the mechanism could

[1] The views expressed by the California Efficiency + Demand Management Council are not necessarily those of its individual members.
[2] Additional information about the Council, including the organization's current membership, Board of Directors, antitrust guidelines and code of ethics for its members, can be found at http://www.cedmc.org. The views expressed by the Council are not necessarily those of its individual members.

create an artificial bid cap and impinge on the procurement rights of LSEs by introducing a round of "second-guessing" of LSE procurement decisions and risk creating an incentive to simply procure the cheapest capacity rather than types of capacity that best conform with each LSE's needs and best contribute to the State's environmental goals. For instance, it may be cheaper in some instances for a CCA to procure fossil-fueled generation but procuring demand response (DR), energy storage, or renewables might be more aligned with its mission and would be more consistent with the Loading Order.

The only consideration of use limitations in the context of the mechanism should be to ensure compliance with the Maximum Cumulative Capacity (MCC) Bucket limitations for DR and other use-limited resources. Though the Council continues to believe that the current MCC Bucket regime is too restrictive for DR, it is in place to ensure that there is a sufficient amount of energy behind the capacity procured to meet RA requirements which is why the procurement of DR and other use-limited resources is limited. Therefore, any additional handicapping based on use-limitations would only be redundant with the procurement limitations enforced by the MCC Buckets.

The Council assumes that the use of the term, "local effectiveness", refers to the effectiveness factors used by the CAISO in its Local Capacity Technical Studies. If so, considering effectiveness factor for DR resources would be particularly difficult because their size and constituent customer mix (and therefore geographic distribution within a subLAP) can be very dynamic. If the Commission has a different definition in mind for "local effectiveness", further clarification is needed. In the meantime, the Commission should avoid further complicating what is already likely to be a very complicated process of getting the Central Procurement Entity (CPE) procurement process off the ground.

2. **How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas)?**

It may be beneficial to apply premiums to some resources to incentivize their procurement, or more appropriately in the context of the CPE model, avoid disincentivizing their procurement. Though D.20-06-002 made clear that procurement of preferred resources should be a priority, whether that will result in additional preferred resources being procured remains to be seen.

Factors on which to base a premium can be resource location, resource type (especially preferred resources), or operational characteristics. A good example is preferred resources located in disadvantaged communities (DACs) that can reduce the need to dispatch fossil-fueled generators, or any type of resource located in a particularly constrained area or sub-area. In addition, premiums could be applied to ensure that preferred resources are considered on a level the playing field with fully-depreciated gas-fired generation.

3. **How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices?**

Premiums should be as transparent as possible if they are to effectively incentivize the desired outcomes. From a conceptual standpoint, market actors cannot make an informed decision on whether to put forth a product if its value is not reasonably known. Similarly, each CPE's least cost, best fit methodology used in their respective procurement processes should be as transparent as possible to ensure that resource providers can develop the products of greatest value.

4. **Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process?**

   The Council has no comment on this question but reserves the right to comment in the future.

5. **How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements?**

   The Council has no comment on this question but reserves the right to comment in the future.

6. **How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?**

Both qualitative and quantitative criteria should be considered. Consistent with D.20-06-002, preferred resources should be favored over fossil-fueled resources and certainly not disadvantaged. One aspect of this is ensuring that preferred resources are fairly compared to existing, fully-depreciated gas resources on a cost basis. In addition, there should be greater consideration given to low- or zero-emission resources to reflect their additional value in meeting the State's environmental goals.

7. **In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.**

   The Council has no specific recommendations on this issue at this time.

Sincerely,

Greg Wikler
Executive Director
California Efficiency + Demand Management Council

Informal Comments of Pacific Gas and Electric Company on Issues Outlined on Pages 43-45 and in Ordering Paragraphs 5 and 6 of Decision 20-06-002 - Due July 20, 2020

Pursuant to the request of the California Community Choice Association and Pacific Gas and Electric Company ("PG&E") dated July 6, 2020, PG&E provides the following informal comments on issues outlined on pages 43-45 and in Ordering Paragraphs 5 and 6 of Decision ("D.") 20-06-002.

1. PAGE 43

How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?

As PG&E has previously mentioned in the resource adequacy ("RA") proceeding, local resources are not equally "effective" in meeting local area reliability needs. Local RA resources may be differentiated by a number of factors, including, but not limited to, energy-limitations deliverability, availability, and dispatchability for the California Independent System Operator Corporation ("CAISO"), based on the specific local area load profile and limited transmission capability and the CAISO's local effectiveness factors for differing contingencies.[1] To address resource "effectiveness" concerns, load serving entities ("LSEs") that voluntarily show local resources should only be compensated for resources that either have been demonstrated to meet up-front eligibility requirements or have an effectiveness adjustment applied to the net qualifying capacity ("NQC") of the voluntarily shown resource. The following is a non-exhaustive list of potential up-front eligibility requirements for consideration by the working group: (1) the resource must be a preferred resource or an energy storage resource, (2) the resource must be category 2 or greater under the California Public Utilities Commission's ("Commission") Maximum Cumulative Capacity construct, and (3) the resource must be available to self-schedule and/or economically bid, at a minimum, during the availability assessment hours. These requirements have been previously discussed and vetted in the RA proceeding and provide a reasonable approach to ensure that a proposed compensation mechanism appropriately values "effective" resources while addressing energy-limitation concerns in meeting local area reliability needs.

Additionally, the central procurement entity ("CPE") should demonstrate that selection of a voluntarily shown resource reduces total customer costs compared to the costs of local procurement if that resource had not been voluntarily shown by an LSE. Specifically, that resource must displace procurement of more expensive local RA capacity. For example, consider a scenario in which a single resource that costs $10 is needed in a sub-local area with a $5 local premium. If an LSE invests in a preferred resource in that sub-local area that does not meet the full local area reliability need and elects to show that resource, customers should not be

[1] http://www.caiso.com/Documents/Final2021LocalCapacityTechnicalReport.pdf, pp. 27-29.

required to pay both the $5 local premium for the preferred resource and the $10 cost of the needed resource; the CPE should only procure the $10 resource in that case.

2. PAGE 44 & ORDERING PARAGRAPH 5

a. How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);

Locational Granularity. PG&E believes it will be difficult to balance the objective of sending the right market signal to ensure development of preferred resources in the most constrained areas with the objective of mitigating market power impacts. Ideally, the proposed compensation mechanism would be calculated for each sub-local area; however, given there is likely substantial market power at the sub-local area level, it is more likely the local premium would reflect that market power. PG&E does not have a solution to this issue at this time but notes the complexity here.

If the primary objective is to ensure the development of preferred resources in locally constrained areas, the proposed compensation mechanism should be as granular as the sub-local areas (e.g. the Moss Landing/South Bay sub-local area in the Greater Bay Area local capacity area ("LCA")). This level of granularity is aligned with how the CAISO reviews and evaluates the effectiveness of the local RA resources to meet the applicable Local Capacity Technical Study criteria as required by CAISO Tariff Sections 43.2.1.1 and 43.2.2 and how the CAISO identifies collective local capacity deficiencies among the service territories of the respective investor-owned utilities.

Establishing a local premium at an aggregated level such as the individual LCA (e.g. Fresno or even the aggregated Other PG&E Area) is not likely to incent the development of preferred resources in locally constrained areas and help California transition from carbon emitting resources in local areas consistent with state policy goals. For example, the Fresno LCA has 2,950 megawatts ("MW") of available capacity to meet an LCA requirement of 1,694 MWs for 2023. However, there remain multiple sub-local areas (e.g. Coalinga, Panoche, Reedley) that do not have sufficient available capacity, have not experienced the development of preferred resources or energy storage resources in recent years or will continue to rely on carbon emitting resources absent new development. Here, an aggregated level local premium would distort the market signal and overcompensate for less constrained areas within the Fresno LCA.

However, PG&E is concerned that, if the proposed compensation mechanism is based on observed prices, a granular local premium could also be inflated due to market power or gamed. This would over-compensate voluntarily shown resources developed in those areas, resulting in harm to customers. As noted in the CAISO Department of Market Monitoring's 2019 Annual Report on Market Issues & Performance, several LCAs are not competitive: "The North Coast/North Bay, Sierra, Stockton, LA Basin, and San Diego/Imperial Valley local areas are not structurally competitive because there is at least one supplier that is pivotal and controls a significant portion of capacity needed to meet local requirements."[2]

Technology Granularity. The proposed compensation mechanism for voluntarily shown resources should reflect the contribution of a resource type to local area reliability. A 4-hour duration battery should not be paid the same local premium as an 8-hour duration battery, nor should a solar resource be paid the same local premium as a solar-plus-storage (battery) resource since there are differentials in how much each of these contributes to local area reliability. Ensuring that the payment to voluntarily shown resources reflects its contribution to local area reliability will incent investment in the resource types that are most "effective" at meeting the reliability needs of a particular LCA or sub-local area. As PG&E mentioned above, an adjustment should be applied to the NQC of the voluntarily shown resource to account for the "effectiveness" of that resource.

b. How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

PG&E understands that publishing transparent local premiums would provide the best market signal for LSEs investing in local preferred resources. However, publication of prices could be problematic two ways: (1) if the local premium is based on observed prices and published at a very granular level (e.g., sub-local area), then market-sensitive bid information could be revealed and (2) publication may influence the behavior of bidders in a way that harms customers, particularly if a large volume of local resources are voluntarily shown. For example, consider an area with a local premium of $5. Any needed resource in that area may continue to bid above $5, and less "effective" resources would be incented to bid just under $5 even if they would ordinarily bid $3. This is because the market participant would effectively know the bids of all voluntarily shown resources in the area. PG&E believes it is possible that many LSEs will elect to voluntarily show resources because they are interested in retaining the system and flexible attributes. While the CPE may be able to monitor for and detect egregious examples of manipulative behavior, it is unlikely to be able to completely mitigate for it.

Potential options for mitigating these concerns include publishing aggregated data upfront and more granular data after a sufficient period of time has passed or publishing rankings (e.g., highest value area to lowest) or tiers with ranges (e.g., top five local premiums include these areas and are between $5 and $7). Aggregation of local premiums would also lesson these impacts but would send less precise market signals as noted above.

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[2] http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf, p. 179.

c. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process;

As part of the CPE's solicitation process, PG&E believes that an LSE should be allowed to either: (1) voluntarily show the resource for a local premium or (2) both bid and voluntarily show the resource for no local premium. In other words, if an LSE would like the voluntarily shown resource to be eligible for the proposed compensation mechanism, the LSE cannot select the option to both bid and voluntarily show the resource as part of the CPE's solicitation process. Allowing a bid and show for a local premium option would incent bidding at high prices behavior for LSEs that are willing to accept a lower local premium.

d. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

Local RA capacity requirements are based on the CAISO's local capacity technical studies and the CAISO ultimately determines whether the capacity procured by LSEs or, in the future, the CPE meets local area reliability needs or requires backstop. For example, in the CAISO's 2021 Local Capacity Technical Study Report, CAISO conducted an analysis on estimated maximum limits on the amount of energy storage resources that can be deployed to displace other local area resources. The estimated maximum limits are based on LCAs and sub-local areas having limited transmission capability and, therefore, must rely on internal local resources to be available to reliably provide energy to serve local load or potential increases to local load during the charging cycle for energy storage. As a result, there is likely diminishing return once the estimated maximum limits are exceeded absent an increase in transmission capability, changes in the local load or changes to the transmission configuration, among other things. Therefore, any effectiveness adjustment to local premiums should reflect the assumptions and findings of the most recent CAISO Local Capacity Technical Study Report.

3. PAGES 44-45

How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?

PG&E does not have informal comments on this issue at this time.

4. ORDERING PARAGRAPH 6

> **In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.**

PG&E believes that it is reasonable for the Commission to consider proposals for legacy treatment of existing contracts that were procured to meet an LSE's local RA requirements prior to the consideration of a centralized procurement framework for local RA resources. PG&E notes that legacy treatment of existing contracts should not be afforded to contracts for local resources that were procured outside of that LSE's transmission access charge ("TAC") area (e.g. a northern California LSE that procured a resource within a southern California LSE's TAC) as those resources were not procured by the LSE to meet local RA requirements but were likely procured to meet the LSE's system RA requirements.

Below, PG&E provides suggested parameters within which a local resource should be deemed to be "existing" for purposes of legacy treatment and how long the legacy treatment should be applied.

Any proposed legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired, prior to the date of issuance of D.19-02-022, March 4, 2019. This date effectively represents the date the Commission affirmed its intent to adopt a centralized procurement framework for local RA resources and the possibility that LSEs may no longer have a procurement obligation for local RA.

PG&E does not support any proposal for legacy treatment that would be applied for the full term of an existing contract or the life of an existing owned resource.

Public Advocates Office

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The Public Advocates Office's Informal Comments on the Treatment of a Local Capacity Requirement Reduction Compensation Mechanism

R.17-09-020 (RA) and R.19-11-009 (RA)
July 20, 2020

Submitted by	Organization	Date Submitted
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INTRODUCTION

Decision (D.) 20-06-002,[1] issued in the California Public Utilities Commission's (Commission) predecessor resource adequacy (RA) proceeding, Rulemaking (R.) 17-09-020, directs the California Community Choice Association (CalCCA) and either Pacific Gas and Electric Company (PG&E) or Southern California Edison Company (SCE) to co-lead a working group to develop a local capacity requirement (LCR) reduction compensation mechanism. On July 6, 2020, PG&E sent an email to the service list of R.17-09-020 and the current RA proceeding, R.19-11-009, providing notice of the working group co-leads (CalCCA and PG&E) and a schedule for the working group activities authorized in D.20-06-002. The July 6, 2020 email requests parties to submit informal comments to the RA service lists on July 20, 2020 regarding a series of questions on the development of a LCR reduction compensation mechanism.

[1] D.20-06-002, *Decision on Central Procurement of the Resource Adequacy Program*, June 11, 2020.

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits the following informal comments in response to questions on the development of a LCR reduction compensation mechanism.

BACKGROUND

D.20-06-002 adopted a Central Procurement Entity (CPE) to procure local RA in the PG&E and SCE Transmission Access Charge (TAC) areas. D.20-06-002 adopted a "hybrid" procurement model that allows load-serving entities (LSEs) to 1) sell their local RA capacity to the CPE, 2) utilize a resource for their own system and flexible RA requirements, or 3) voluntarily show the resource to both meet their own system and flexible RA requirements and also reduce the amount of local RA the CPE will need to procure for the area.[2] Under the third option, the LSE would not sell the capacity to the CPE; rather, the capacity would be shown to exist and would be used to meet the local RA requirements wherever the capacity is located. Moreover, under the third option, the LSE would not receive a one-for-one credit as if it had sold the capacity to the CPE.[3]

In response to comments on the proposed decision, D.20-06-002 also stated that "[t]he Commission will develop an LCR reduction compensation mechanism, if details can be assessed and developed" in a future decision.[4] The Commission called for a working group to consider an LCR reduction compensation mechanism which may provide a financial credit for preferred[5] and energy storage resources.[6] An LCR reduction compensation mechanism may[7] essentially create a pre-determined premium adjusting how the CPE values and pays for a local preferred resource or energy storage resource that is offered to the CPE by an LSE.

[2] D.20-06-002, p. 23.

[3] Since the CPE procures local RA to meet requirements and shares that costs to all LSEs in the local area, Option 3 would only reduce a single LSE's costs proportional to their share of the net costs that were reduced by showing, but not selling, the local RA capacity. (D.20-06-002, pp. 23-24.)

[4] D.20-06-002, p. 43.

[5] Cal Advocates notes that "preferred resources" is not defined in D.20-06-002 but assumes the same definition defined in the State's Energy Action Plan II, October 2005, p. 2: energy efficiency, demand response, renewable resources, distributed generation.

[6] D.20-06-002, p. 42.

[7] The precise nature of the mechanism is yet to be determined as no proposal for its design has been presented.

A working group meeting is tentatively scheduled for July 27, 2020 to discuss proposals and consider stakeholder informal comments.

DISCUSSION

Cal Advocates provides the following comments in response to the questions identified in the July 6, 2020 email from the working group co-leads.

1. **How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?**

The mechanism should not include any value if the resource is unable to provide local RA capacity. The CPE will only procure the local RA attributes of an offered resource in solicitations.[8] The effectiveness and ability of a resource to provide those local RA attributes should match or exceed the requirements of the Commission and/or California Independent System Operator (CAISO) that qualify specific technologies' ability to count as local RA. The mechanism should not give any value to a resource that does not provide local RA with respect to regulatory standards. The mechanism also should not provide a higher premium for particularly effective resources because local RA capacity is agnostic of effectiveness beyond the requirements to qualify as local RA. Exceptionally effective resources are already compensated in the CAISO markets through their ability to provide flexible capacity, residual unit capacity, or ancillary services, and may also be used to meet non-RA requirements like Renewable Portfolio Standards (RPS) compliance amounts, and Assembly Bill (AB) 2514 energy storage compliance volumes.[9]

2. **Should different premiums be developed for different types of preferred resources (e.g., for different types of resources, new versus existing resources, and/or for sub areas, individual local areas)?**

If an LCR reduction compensation mechanism is adopted, there should be pre-determined premiums calculated for each resource technology type, similar to how production and investment tax credit rates have been set differently for solar and wind resources. This may allow the Commission to value different technologies depending on their suitability to meet state

[8] Other attributes like flexible RA are credited back to the Seller, no energy is transacted, and dispatch rights are optional and have a means of recovery. (D.20-06-002, Ordering Paragraphs 8 and 19.)

[9] Public Utilities Code Section 9620(c).

climate change goals and provide incentives to specific technologies which can best meet the state's goals.

3. How should the premiums be made as transparent as possible?

If a mechanism is adopted, the Commission should post the premium rate(s) to the service list and include them in both its annual Resource Adequacy Report and the annual Final RA Guide. This may not be feasible if a premium is created for each unique resource since it may be calculated depending on market sensitive resource information.

4. Should the compensation mechanism preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process?

Cal Advocates has no response to this topic at this time.

5. How should the local compensation from year to year be adjusted to account for changes in the effectiveness of the resource reducing the local requirements?

The premium should be a rate based on the net qualifying capacity (NQC) of the resource. This rate would allow the total payout of the premium to increase or decrease as the NQC is adjusted year to year. While the NQC may not capture the entire scope of a resource's "effectiveness," it is the primary expression of a resource's local RA capacity value and is being used by the LSE and/or CPE to meet local RA requirements.

6. How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?

Cal Advocates has no response to this topic at this time.

7. Please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.

Cal Advocates has no response to this topic at this time.

CONCLUSION

The Public Advocates looks forward to attending the LCR Compensation Mechanism working group meeting tentatively scheduled for July 27, 2020 to discuss proposals and consider stakeholder informal comments on these issues.

Please contact Patrick Cunningham at Patrick.Cunningham@cpuc.ca.gov or 415-703-1993 with any questions regarding these comments.

Southern California Edison Company's Informal Comments Regarding Local Capacity Requirement (LCR) Reduction Compensation Mechanism and Existing Contracts
July 20, 2020

Southern California Edison Company (SCE) appreciates the opportunity to submit informal comments on issues related to a potential LCR reduction compensation mechanism and treatment of existing resource adequacy (RA) contracts as outlined in Decision 20-06-002 (Final Decision). The comments below address the questions set forth in the July 6, 2020 email of the Working Group co-leads.

1. **<u>Page 43: How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?</u>**

SCE understands this question is intended for new resources, given that Question #4 below explicitly addresses whether any proposed mechanism should be applied to existing contracts. With this understanding, new resource development should be addressed in the Integrated Resource Planning (IRP) proceeding and other applicable proceedings (e.g., Renewables Portfolio Standard) that address new resource development and procurement. The Final Decision recognizes that local preferred resources will be developed without a financial credit mechanism, stating:

> [W]e believe the [investor-owned utility (IOU)] acting as the [central procurement entity (CPE)] allows for development of local preferred resources, even without a financial crediting mechanism. This is especially true for locally constrained areas that involve transmission solutions, such as recent successful centralized procurement by IOUs in the Moorpark/Santa Clara and Moss Landing/South Bay sub-local areas…. [A] hybrid model does not disincentivize procurement of local resources because [load-serving entities (LSEs)] procure local resources for many reasons beyond the local RA value.[1]

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[1] Final Decision at 40-41.

Therefore, SCE recommends the starting point to answering this question should be to recognize that the IRP proceeding and other applicable proceedings are the appropriate venues for discussion of new resource development, which is a responsibility that applies to all LSEs.

Nevertheless, there are various questions and issues that should be considered in evaluating a potential LCR reduction compensation mechanism. First, it can be difficult to determine the local RA value of a new resource in advance of CPE procurement due to market dynamics and the timing of procurement (e.g., one to three years ahead and for new resources, with a likely term of 10-20 years even if the CPE only contracts with the LSE for a shorter time frame). An LCR reduction compensation mechanism would need to ensure the local RA premium[2] is pre-determined, as required by the Final Decision, to mitigate market power concerns.[3] The mechanism would also need to ensure that the pre-determined premium represents a reasonably accurate local RA value for the resource, consistent with the market conditions at the time when the CPE procurement is actually conducted.

Second, when local effectiveness of a resource is considered, it can be difficult to pre-determine the local RA value since the effectiveness factor can vary year-by-year, depending on the portfolio of resources included in the local study that determines the local need. Third, while the resource may be needed for a local area currently, the need may change in the future; therefore, it can be inappropriate to compensate a resource at a pre-determined premium when the need does not exist or decreases in the future years, unless the pre-determined premium is tied to the market conditions at the time of the resource's actual contribution to the local RA need (which again can be difficult when the premium is pre-determined).

Finally, it should be evaluated whether the California Independent System Operator (CAISO) would need to provide the information on effectiveness factors and the value of use-limited resources in meeting a local area need in its LCR studies. This information would be

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2 SCE utilizes the term "premium" to denote the value of a resource meeting a local area need that is above the value of a resource not meeting the local area need (i.e., the difference in value between local and system RA).

3 *See* Final Decision at 42.

needed to derive a pre-determined local RA premium tailored to the effectiveness and use limitations of the resource. During workshops related to the topic of effectiveness factors, the CAISO indicated that effectiveness is not something that can be determined *a priori*. Rather, effectiveness is determined by the fleet of resources available and the contingencies that the fleet meets. Based upon these factors, creating a pre-determined local premium that accounts for effectiveness may be a difficult, if not impossible, task. Such a premium may be determined after-the-fact but would then not be able to inform the procurement decision of the CPE during their solicitation, and would be inconsistent with the Final Decision.

2. **Page 44 & Ordering Paragraph 5:**

a. **How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas)?**

As noted above, the premium should reflect the actual contribution to the local RA need of a resource and market conditions. When different types of preferred resources have the same contribution, then their premium should be the same; in other words, the premium should be on a MW-basis for preferred resources, new or existing. On the question of whether there should be different premiums for sub-areas, individual local areas, or Transmission Access Charge-wide local areas, such granularity should consider, and very likely depend on, data availability and the robustness of the data that report historic RA prices for these areas.

b. **How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices?**

SCE strongly agrees that transparency and potential market sensitivity of the premiums should be considered. The transparency of the premiums would depend heavily on the data used to determine the premiums. If such data are based on the public Commission RA Reports, which are published annually, then the transparency issue is addressed because those reports contain aggregated data that remove market-sensitive information. If such data are based on some other sources, then those sources should be evaluated to ensure the desired level of transparency can be provided while appropriately protecting market-sensitive information.

c. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process?

Given the complexity of the iterative process and the potential interaction between the iterative process and the compensation mechanism, SCE recommends that this topic be discussed in workshops. In particular, the workshops must examine the potential for gaming of bids based upon known minimum premium values and the resultant efficiency of the procurement process.

d. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements?

The answer to this question would depend on the details of the mechanism and specifically, how the effectiveness of resources is considered in deriving the premium. For instance, if the premium is based on the CPE procurement costs, which may account for the effectiveness of resources in its bid selection (assuming the resource is selected by the CPE), then the changes in the effectiveness of resources may already be incorporated in deriving the premium. Since the purpose of compensating a resource at a local premium is to ensure the resource is contributing to meeting a local RA need, the question implies that any resource that receives the local RA premium will be picked up by the CPE. However, not all resources will be picked up by the CPE. This may happen for several reasons. The CPE is anticipated to conduct its procurement in consultation with the CAISO to evaluate effectiveness of the procured fleet. It is therefore possible that the effectiveness of the shown resource seeking the fixed local premium payment is so ineffective that it does not eliminate other procurement and as such, the payment of the premium becomes excess procurement by the CPE. It is also possible that another equally effective resource is offering to sell its RA to the CPE, which would include system and flex in addition to the local attribute. If the price of this resource is very near the fixed price premium, customers would be better off to procure the resource with the system and flex attributes rather than pay the premium and receive only the local RA attribute. These issues should be discussed in the workshops.

3. **Pages 44-45: How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?**

SCE recommends this question be addressed in the area of CPE implementation as it relates to the bid selection process and bid selection criteria. This question addresses how the CPE will fairly implement the least-cost, best-fit procurement criteria. It addresses differences between gas and renewable resources as a general matter and is not focused on the premium of a local resource over system resources.

4. **Ordering Paragraph 6: In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.**

SCE proposes that the LCR reduction compensation mechanism should apply to only those existing resources signed before the issuance date of the Proposed Decision on Central Procurement of the Resource Adequacy Program, which was issued in R.17-09-020 on March 26, 2020. For contracts that are signed after this date, contracting parties would have known the potential of the central procurement of local RA, which has been a part of the scope of the RA proceeding for some time. Indeed, the Commission first determined that central procurement of local RA was needed almost two years ago in its Track 1 decision, finding that "we believe that a central buyer system - for at least some portion of local RA - is the solution most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection."[4]

The LCR reduction compensation mechanism for new resources could apply to contracts signed prior to the proposed decision; therefore, this limitation is only for local RA contracts with existing resources. Local RA contracts with existing resources would likely have been signed for three- to five-year durations. As such, SCE proposes that the payment of an LCR reduction compensation mechanism for existing resources should be for up to a five-year term length.

4 Decision 18-06-030 at 32.

July 20, 2020

INFORMAL COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY REGARDING THE WORKING GROUP ON THE LOCAL CAPACITY REQUIREMENT COMPENSATION MECHANISM AND TREATMENT OF EXISTING CONTRACTS (R.17-09-020 & R.19-11-009)

San Diego Gas & Electric Company ("SDG&E") appreciates this opportunity to provide informal comments regarding the Working Group on the Local Capacity Requirement ("LCR") Compensation Mechanism and Treatment of Existing Contracts. Pursuant to Decision ("D.") 20-06-002, the Commission authorized a working group to "develop [an LCR] reduction compensation mechanism that properly compensates load-serving entities for shown local preferred and energy storage resources."[1] The Commission further directed that "[t]he working group . . . shall also consider and submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing contracts."[2] The Commission also made clear that it "is not open to considering a one-for-one credit, CalCCA's proposed financial credit mechanism, or a credit mechanism for fossil fuel resources (other than potentially for existing grandfathered contracts)."[3]

Thus, SDG&E understands the LCR reduction compensation mechanism ("Mechanism") to apply to only three categories of shown resources:

1. All energy storage;
2. All preferred resources; and
3. Grandfathered contracts of existing fossil fuel resources.

For Categories 1 and 2, resources self-procured and shown by a load serving entity ("LSE") should receive a premium payment regardless of when the resource was or will be procured. However, Category 3 resources must be existing fossil fuel resources and contracts must be executed prior to a specific date. SDG&E proposes that grandfathered contracts be required to have a contract execution date prior to, June 11, 2020, the date D.20-06-002 was adopted. Similarly, for fossil fuel resources that are owned and not contracted by an LSE, including those owned by an Investor Owned Utility ("IOU"), the Commission should require the resource to have an approval date or online date prior to June 11, 2020.

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1 D.20-06-002, Ordering Paragraph 5.
2 *Id*. at Ordering Paragraph 6.
3 *Id*. at p. 43.

Local Premium

The Commission seeks feedback regarding "[h]ow granular the premium should be (*e.g.,* should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas)."[4] The Commission uses the term "premium" because when LSEs show local resources, LSEs retain the system and flexible RA attributes, whereas when the LSE offers and sells the RA attributes to the central procurement entity ("CPE"), it does not retain any RA attributes. Therefore, the LSE is only "showing" the Local RA attribute while keeping all other attributes and products associated with the Local resource. SDG&E proposes that all resource types in the three categories of shown resources receive the same premium rather receiving than technology-specific premiums. While SDG&E understands that each resource type has different capacity costs, SDG&E believes the complexity of developing individual premiums for the various types of resources in either sub-areas or local areas makes this task infeasible.

In order to calculate the premium, the CPE would need to compare the prices of Local RA and System RA attributes in order to determine the Local premium. SDG&E proposes that the CPE utilize the relevant Power Cost Indifference Adjustment ("PCIA") System RA Market Price Benchmark ("MPB") for its area, either NP-15 or SP-15 for the compliance year. The System RA MPB is typically available in November prior to the compliance year. SDG&E suggests consideration of the weighted average price of Local resources that were contracted by the CPE for the compliance year. This means that the CPE must identify the specific cost related to RA capacity procured if it procured other attributes, such as Flexible RA or energy tolling. This is necessary to ensure an apples-to-apples comparison. Another approach would be to use the PCIA Local MPB, however it is unclear how the CPE procurement of Local resources will impact the PCIA Local MPB calculation. Therefore, in the interim, SDG&E recommends using prices relevant to CPE procurement. SDG&E believes that both values can be made publicly available in November after the CPE has finished its procurement along with the publication of the annual PCIA MPBs.

While it may be the case that advance knowledge of the premium value could factor into an LSE's decision to show or offer, SDG&E does not believe that advance knowledge is necessary since LSEs would still be able to show the resource if the offer is not selected by the CPE. In this sense, the LSE does not lose any optionality in maximizing value for its customers.

Effectiveness Factors

Decisions regarding effectiveness factors should be guided by the California Independent System Operator ("CAISO") and the annual Local Capacity Technical Study ("LCTS"). It may be possible to incorporate each resource's effectiveness factor into the Mechanism. However, to the extent the methodology is too complex, SDG&E offers a simple alternative until a more precise methodology can be adopted. SDG&E proposes that the effectiveness factors for all shown resources be calculated based on the percentage resulting from the local or sub-area LCR divided by the total amount of capacity shown and CPE procured capacity. For instance, if the

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[4] *Id*. at p. 44.

LCR is 100 MWs and 40 MWs were shown by LSEs, and 80 MWs were procured by the CPE, the percentage would be 100 MW / 120 MW, or 83.33 percent. LSEs that showed the total of 40 MWs would receive a credit of approximately 33.33 MWs, assuming that all volumes were within one of the three categories listed above. This method could be further modified to also incorporate any backstop procurement performed by the CAISO during the year ahead process, such as capacity procurement mechanism or reliability must run ("RMR") contracts.

Duration

SDG&E proposes to allow LSEs to show Local RA resources annually on a three rolling year basis. Although LSEs may have shown or offered Local RA resources for a three-year period, changes to the LCR, particularly increases, will require additional capacity for the next three-year period. As CPE procurement moves into future years, additional years will need to be procured or shown by LSEs. LSEs should have the opportunity to show additional resources not shown or procured by the CPE previously. Under SDG&E's proposal, shown local RA capacity is committed for a period of up to three years. There would not be a process to decommit a resource except for certain reasons, such as resource retirements or force majeure. If an LSE sells its shown Local RA to another LSE, it must notify the CPE so that the CPE can validate that all shown RA resources continue to be shown even by the new LSE.

SDG&E does not propose a separate rule for grandfathered contracts. However, SDG&E is not opposed to a one-time election for grandfathered contracts in which the grandfathered contracts would be committed for the term of the contract which may exceed the rolling three-year Local RA program.

Cost Allocation

The premium associated with the shown local RA capacity would reduce the costs allocated to the LSE by the CPE for the procurement. This means that the CPE must collect the premium from LSEs in order to remain balanced. For example, in the example below, CPE procurement results in $5,000,000 of cost for 2023 in a Local area. The shown RA Premium is $10/kW-year. Each LSE and IOU has their respective load ratio shares as well as their shown RA which totals to 360 MWs and a calculated premium of $3,600,000. If the CPE were to net out the premium payments from that of the CPE procurement from each LSE, the CPE would only collect $1,400,000 from all LSEs and would not have sufficient funds to pay for the original CPE procurement of $5,000,000.[5] This example is illustrated in Table 1 below.

[5] This example uses a simplified assumption that all shown RA volumes are 100 percent effective. To the extent shown RA volumes do not all qualify for the Mechanism, or the effectiveness is not calculated to be 100 percent, the volumes would be impacted as well as the total premium that would be collected and netted.

Table 1

CPE Procurement	$5,000,000
Shown RA Premium ($/kW-yr)	$10
Total CPE Costs with Shown RA Premium	$8,600,000

	LSE A	LSE B	LSE C	IOU	Total
Load Ratio	10%	20%	15%	55%	100%
Shown RA (MW)	100	50	10	200	360
Shown RA Premium	$1,000,000	$500,000	$100,000	$2,000,000	$3,600,000
CPE Procurement Cost Allocation	$500,000	$1,000,000	$750,000	$2,750,000	$5,000,000
CPE Costs to be collected	**($500,000)**	**$500,000**	**$650,000**	**$750,000**	**$1,400,000**

Based on Table 1 above, the shown RA premiums must also be collected from LSEs in order to ensure the CPE is able to pay for the CPE procurement. In this case, each LSE would receive their ratio share of the total CPE costs (including any premiums incurred). LSEs would then pay their ratio share of the total cost less any premium for their shown resources. If an LSE's premium exceeds its load ratio share of the total cost, the CPE would pay the LSE that amount from the funds collected. Table 2 below illustrates this concept.

Table 2

CPE Procurement	$5,000,000
Shown RA Premium ($/kW-yr)	$10
Total CPE Costs with Shown RA Premium	$8,600,000

	LSE A	LSE B	LSE C	IOU	Total
Load Ratio	10%	20%	15%	55%	100%
Shown RA	100	50	10	200	360
Shown RA Premium	$1,000,000	$500,000	$100,000	$2,000,000	$3,600,000
Total CPE Costs with Shown RA Premium	$860,000	$1,720,000	$1,290,000	$4,730,000	$8,600,000
LSE cost allocation net of Premium	**($140,000)**	**$1,220,000**	**$1,190,000**	**$2,730,000**	**$5,000,000**

The annual LSE cost allocation net of the premium may change based on new effectiveness factors as well as new premium values.

SDG&E submits that the proposal above allows LSEs to receive appropriate compensation for their investments in self-procured local resources shown to the CPE.

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APPENDIX C

JULY 27, 2020 WORKING GROUP WORKSHOP PRESENTATIONS

Working Group Workshop on Local Capacity Requirement Reduction Compensation Mechanism and Treatment of Existing Contracts

Co-Leads: California Community Choice Association & Pacific Gas and Electric Company

July 27, 2020

Agenda

Introduction and Safety	10:00 AM
Procedural Background	10:05 AM
Workshop Goals	10:15 AM
Summary of Informal Comments	10:20 AM
Parties’ Proposals (PG&E, CalCCA, SDG&E)	11:00 AM
LUNCH BREAK	1:00 PM
Discussion	1:45 PM
Next Steps	3:45 PM

Procedural Background

- Resource Adequacy (RA) Central Procurement (CP) framework June 11, 2020 Decision (D.20-06-002)
  - Adopted a central procurement structure for local RA beginning with the 2023 RA compliance year
  - PG&E and SCE to act as CP entities (CPEs) in their respective Transmission Access Charge (TAC) areas
  - Authorized a working group (WG) to develop and assess proposals regarding:
    - A local capacity requirement (LCR) reduction compensation mechanism to compensate LSEs for shown local preferred and energy storage resources
    - Treatment of existing local RA contracts
    - CalCCA and either PG&E or SCE to be co-leads (PG&E will serve as a co-lead)
    - Proposals offered for consideration to be presented through a WG report

Workshop Goals

- Gain a shared perspective on the intent and boundaries of D.20-06-002
- Present party proposals and perspectives on compensation mechanisms for local RA and the treatment of existing local RA contracts
- Explore party proposal and perspectives to advance development of solutions
- Identify areas of consensus and non-consensus
- Establish next steps

Summary of Parties' Informal Comments

1. How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?

- CalCCA: Incorporated not through a price reduction, but into a technology-specific modification of the MW; CAISO should lead a stakeholder process to develop factors that could be used.
- CalPA: The effectiveness and ability of a resource to provide those local RA attributes should match or exceed the requirements of the Commission and/or CAISO that qualify specific technologies' ability to count as local RA.
- PG&E: Local resources are not equally "effective" in meeting local area reliability needs; Should only be compensated for resources that either have been demonstrated to meet up-front eligibility requirements or have an effectiveness adjustment applied to the NQC.
- SCE: Local effectiveness is determined by CAISO based on the fleet of resources available and the contingencies that the fleet meets; CAISO would need to provide the information on effectiveness factors and the value of use-limited resources in meeting a local area need in its LCR studies.
- SDG&E: Should be guided by the CAISO and the annual Local Capacity Technical Study.
- CESA: Favors an approach where the CPE RFO considers identifying multiple portfolios of bid and shown resources that, on one end, considers effectiveness as the binding, initial screening criteria and, on the other end, more heavily considers preferred attributes while ensuring effectiveness.
- Council: Cost effectiveness of local resources should not be within the scope of the mechanism.

2. How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas)?

- CalCCA: Price premiums would be differentiated by local areas, including the disaggregated "PG&E Other" areas, unless a higher level of aggregation were required to mask the price of individual resource prices.
- CalPA: There should be pre-determined premiums calculated for each resource technology type.
- PG&E: Ideally, the proposed compensation mechanism would be calculated for each sub-local area; Should reflect the contribution of a resource type to local area reliability.
- SCE: The premium should reflect the actual contribution to the local RA need of a resource and market conditions; The level of granularity should consider, and very likely depend on, data availability and the robustness of the data that report historic RA prices for these areas.
- SDG&E: Believes the complexity of developing individual premiums for the various types of resources in either sub-areas or local areas makes this task infeasible
- CESA: Generally supports granularity of the LCR reduction compensation mechanism and proposed the following premiums for consideration (1) closer-to-load, (2) DAC, (3) GHG emissions reduction and (4) market power mitigation; A one-size-fits-all premium may undercut the incremental value-add of certain projects.
- Council: Factors on which to base a premium can be resource location, resource type (especially preferred resources), or operational characteristics or for resources located in DACs.

3. How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices

- CalPA: The Commission should post the premium and include them in both its annual RA Report and the annual Final RA Guide; This may not be feasible if a premium is created for each unique resource since it may be calculated depending on market sensitive resource information.
- PG&E: Potential options include publishing aggregated data upfront and more granular data after a sufficient period of time has passed or publishing rankings (e.g., highest value area to lowest) or tiers with ranges (e.g., top five local premiums include these areas and are between $5 and $7).
- SCE: The transparency of the premiums would depend heavily on the data used to determine the premiums.
- CESA: One way to balance transparency with the need for confidentiality would be to consider base class-specific premiums that are broadly applicable to all resources within that class.
- Council: Should be as transparent as possible to ensure that resource providers can develop the products of greatest value.

4. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process.

- CalCCA: LSE must chose to either bid or show
- CESA: LSE may bid and/or show
- PG&E: LSE may 1) voluntarily show a resource for local premium but may not bid or 2) bid and voluntarily show the resource for no local premium
- SCE: Due to complexity, recommends this be discussed in workshops evaluating gaming risk

5. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

- CESA: Year-to-year adjustment to the local CM should not be established and may not be needed
- PG&E: Any effectiveness adjustment to local premiums should reflect the assumptions and findings of the most recent CAISO Local Capacity Technical Study Report
- Public Advocate: Premium would increase or decrease as NQC is adjusted year to year
- SCE: Depends on details of the mechanism on how the effectiveness of resources is considered in deriving a premium

6. How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?

- CESA: CPE RFO evaluation criteria mirror the premium factors in the local CM, link to IRP-identified future long-term procurement needs in local or sub-local areas, adhere to the loading order and SB 1136
- Council Both qualitative and quantitative criteria should be considered; preferred resources - favored over fossil-fuel resources and not disadvantaged, fairly compared to existing, fully-depreciated gas resources on a cost basis; greater consideration to low- or zero-emission resources in meeting State's environmental goals
- SCE: Recommends to be addressed in the area of CPE implementation as it relates to the bid selection process and criteria

7. In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.

- CalCCA: Compensation mechanism adopted for preferred resources should be applied to existing contracts entered into by an LSE before June 11, 2020; not apply to fossil UOG, which will be required to bid into the solicitation
- PG&E: Legacy treatment of LSE's local RA existing contracts should be applied only to contracts executed, or owned resources that were acquired, prior to issuance of D.19-02-022(3/4/2019); not to local resources procured outside of the LSE's TAC area; do not support being applied for the full term of an existing contract or the life of an existing owned resource
- SCE: Apply to only those existing resources signed before the issuance of central procurement decision on 3/26/2020; for new resources it could apply to contracts signed prior to the PD, therefore limitation is only for local RA contracts with existing resources - up to a five-year term length
- SDG&E: Do not propose a separate rule for existing contracts, but not opposed to a one-time election exceeding the rolling three-year Local RA program

Additional Comments

- AReM: The ability for a LSE to receive a payment from the CPE must not result in over-procurement by the CPE with the over-procurement costs spread among all LSEs.
- AReM: The customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; they should not spread those costs to other LSEs or to the customers of other LSEs.
- CalCCA: Use of a median referent price, which is unaffected by high outliers in a price distribution.
- CalCCA: Recommends that resources be committed for a three-year term; Showing, like a successful bid, should be documented through a confirm.
- SDG&E: Shown local RA capacity is committed for a period of up to three years; No process to decommit a resource except for certain reasons, such as resource retirements or force majeure.

Party Proposals

Lunch Break
45 minutes

Discussion

1. How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?
2. How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);
3. How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;
4. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process; and
5. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.
6. How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?
7. In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.

Next Steps

- **Week of July 27** – Co-Leads to send a matrix to help WG participants to provide positions
- **August 3** – WG participants to provide informal comments on workshop and proposals, with the above matrix filled out
- **August 12** – Co-Leads to email Draft WG Report to WG participants for review
- **August 17** – WG participants to email comments on the Draft WG Report to Co-Leads
- **September 1** –Co-Leads to file Final WG Report on consensus and non-consensus items to CPUC
- **Q4 2020** – Proposed Decision (expected)

Workshop for July 27, 2020

C-18

Scope of the Working Group

<u>Scope</u>

The Commission will develop an LCR reduction compensation mechanism, if details can be assessed and developed

1. <u>LCR Reduction Compensation Mechanism (LCR-CM)</u>: Appropriately compensates LSEs for shown local preferred resources

2. <u>Treatment of Existing Contracts</u>: Contracts that have been procured in anticipation of multi-year local obligations for 2023 and beyond, including consideration of whether any proposed LCR-CM should be applied to existing contracts

<u>Out-of-Scope</u>

- One-for-one credit
- CalCCA's proposed financial credit mechanism (difference between weighted average price of CPE procurement and system average price)
- A credit mechanism for fossil fuel resources (other than potentially for existing contracts)

PG&E's LCR-CM Principles Informed by D.20-06-002

	The Compensation Mechanism Should…	Decision Language
1	**Incent preferred resource development in local areas** to reduce dependence on fossil-generation for reliability	"[P]rovides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas." (p. 41)
2	Reflect the **effectiveness** of a resource at meeting reliability requirements to prevent "leaning" by LSEs	"[C]onsiders local effectiveness factors and use limitations to the shown MW value would more closely align the financial compensation with the actual LCR MW reduction the resource provided." (p. 42)
3	**Result in lower total costs** to customers without sacrificing local area reliability	"[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources." (p. 42) "[E]nsures that ratepayers are: (1) only compensating resources to the extent they provide ratepayer value…."(p. 43)
4	**Not be reflective of market power and/or introduce gaming opportunities** but may reflect a "premium" based on the additional cost of developing resources in local areas	"[A]nother benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums." (p. 42) "[E]nsures that ratepayers are: ….(2) only compensating LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs." (p. 43) "To the extent that market power inflates local area capacity prices, an ex post benchmark would exacerbate this problem by providing inflated prices to local resources shown by LSEs." (p. 42)

Part I: Establishing the Price for the LCR-CM

PG&E has not identified a mechanism for developing a price that clearly meets the decision-informed principles. A "workable" solution must be paired with a transparent and appropriate effectiveness adjustment and demonstration of reduction in total costs to customers.

PG&E has considered 2 options for developing a local price, each with drawbacks:

1. Cost-Based – set the price based on the difference in developing a resource within a local area and a system resource
   - Potential data sources: Padilla report data request, PCIA data request, new data request
   - Issues: data may be too thin, potentially requires aggregation (e.g., resource type, local areas) and the use of stale data; administratively complex
2. Market-Based – set based on the results of CPE procurement
   - Issues: may be reflective of market power, which could result in overcompensating resources and gaming (bidding in essential resources at high prices and showing ineffective resources)

In order to send the correct market signals, the LCR-CM should be as granular as possible:

- Sub-local area granularity: aligned with CAISO Local Capacity Technical Study criteria
- Establishing a local premium at an aggregated level such as the individual LCA (e.g. Fresno or even the aggregated Other PG&E Area) could overcompensate for less constrained areas within the individual LCA and distort market signals

Part II. Applying an Effectiveness Adjustment

Developing effectiveness adjustments using CAISO effectiveness factors is highly complex and potentially infeasible. PG&E is considering whether other ways of assessing resource effectiveness may be "workable."

Challenges with translating effectiveness factors into qualifying capacity or price effectiveness adjustments

- Effectiveness factors represent only the single most binding constraint in a local area. Local areas have numerous constraints and a resource's effectiveness varies by constraint; Effectiveness factors of a resource depends on the evaluation of portfolio as a whole.
- Should not further complicate CAISO's local study process

Alternative Measures of Effectiveness

- Resources may be differentiated by a number of factors including energy-limitations deliverability, availability, and dispatchability for the CAISO
- Considerations:
  - <u>Peak-based</u> - an adjustment could be applied to the NQC to reflect the resource's contribution to meeting the reliability needs (e.g., peak requirement) of a particular LCA or sub-local area as defined in the CAISO Local Technical Study
  - <u>Energy-based</u> – MCC buckets or similar construct could be adapted to ensure resource is available when it is needed
  - <u>Technology-based</u> – not all resource types are equally effective at meeting reliability needs and should be compensated accordingly (e.g., 4-hour versus 8-hour duration battery)

Part III. Ensuring Customer Value

The LCR-CM should not result in an increase in total costs to customers. Resources paid through this mechanism must be lower cost than its alternative, and the mechanism must not be game-able.

Ensuring consistency with least-cost, best-fit

- If the LCR-CM results in lower total costs but sacrifices local area reliability, then the CPE should not accept the shown resources. Otherwise, all customers will be subsidizing the customers of the LSE showing the resources.
- A procurement run with and without shown resources could demonstrate overall cost savings or cost increase, but running for each shown resource would add significant complexity.

Gaming concerns – PG&E is concerned that the LCR-CM may introduce gaming opportunities.

- <u>Bidding expensive, show cheap</u> – Potential for a pattern whereby older, more expensive essential resources are bid, creating a high LCR-CM price, and cheaper, less effective resources are shown. Shown resources would then be paid more than their marginal costs.
- <u>Bid to the Premium</u> - If a high volume of resources are shown in a given local area, other resources in that area may adjust their price based on the premium so that the premium becomes a cap for otherwise cheaper resources.

CALCCA
ADVANCING LOCAL ENERGY CHOICE cal-cca.org

Resource Adequacy Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) Workshop

July 27, 2020

Evelyn Kahl, CalCCA
Matt Langer, Clean Power Alliance
Doug Boccignone (Flynn), CalCCA

C-24

CalCCA Topics Overview

- Decision Constraints
- Frameworks to Address Constraints
  - #1 Selection of shown local attribute assured; price adjusted for effectiveness
  - #2 Selection of shown local attribute not assured; CPE assesses effectiveness
- LSE Showing and Bid Elections
- Existing Contracts
- Other Considerations

D.20-06-002 Constraints
Resource Effectiveness

Working group must address:

- "[R]esource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources." [O¶ 5.d.]
- "[H]ow to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements." [O¶ 5.d.]

Premium must "only compensate[]resources to the extent they provide ratepayer value" and "only compensating LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs" [43]

D.20-06-002 Constraints
Resource Effectiveness (2)

CPE selection criteria must include (1) "Local effectiveness factors, as published in the California Independent System Operator's Local Capacity Requirement Technical Studies" [O¶ 14.b.] and "Energy-use limitations" [O¶ 14.h.]

"Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSEs seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE" [42]

D.20-06-002 Constraints
Premium Calculation

"[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [42]

Premium must "only compensate[]resources to the extent they provide ratepayer value" [43]

A "benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums" [42]

D.20-06-002 Constraints
Premium Calculation (2)

Working Group must address:

- "How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas)" [O¶ 5.a.]
- "How to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices" [O¶ 5.b.]

Principles Gleaned from D.20-06-002

Premium must:

- Be pre-determined
- Provide transparency
- Avoid influence of "market-power inflated price premiums"
- Reflect resource effectiveness and use limitations to ensure ratepayer value and least-cost procurement

D.20-06-002

Alternative Interpretations

1. Shown resource local attributes are "must-take" for the CPE, but premium must be pre-determined, adjusted for resource effectiveness and use limitations, and transparent
2. Shown resource local attributes are considered alongside bids in the CPE solicitation at a pre-determined price and may be rejected by the CPE depending on their value relative to bid resources

Pre-determined Price Calculation

Year 1: Use the median price from the last two quarters of Energy Division PCIA responses for both system and local RA; subtract system price from local RA price and multiply by effective MW or use average prices from the same sources excluding prices that are deemed to have been inflated by market power

Subsequent Years: Use the median price from the last two quarters of Energy Division PCIA responses for system RA and the most reported CPE solicitation results for local RA price; subtract system RA price from local RA price and multiply by effective MW or use average prices from the same sources excluding prices that are deemed to have been inflated by market power

Straw Proposal #1
Overview

Local attribute is treated as “must take” by the CPE

Pre-determined price

- Compare prior year’s local RA premiums paid by CPE at local area granularity to most recent system RA prices collected by Energy Division
- Would be public

Effectiveness adjustment alternatives

- Apply CAISO-determined effectiveness factors, scaling the % to the average effectiveness of the resources procured in the local area
- Adjust use-limited resources by technology (e.g., battery storage) scaled to average battery storage duration of the resources selected by CPE in the local area OR use CAISO Local Capacity Technical Study Report if no use limited resources displaced/selected for the local area

Straw Proposal #1
CAISO Effectiveness Factor Adjustment

- Reference Attachment B of CAISO Local Capacity Technical Report (LCTR) and Operating Procedure 2210Z which provide effectiveness % for each generating unit
- Identify the effectiveness factors of the resources procured in the local area
- Scale the effectiveness of the shown resource to the average effectiveness factor (e.g., 50% average, 25% shown resource = 50% effectiveness adjustment)
- Adjust number of MW eligible for premium by effectiveness adjustment %

Straw Proposal #1
Use Limited Resource Adjustment

Battery storage

- Scale battery storage duration to average duration of the resources selected by CPE in the local area OR, if none selected
- Reference data underlying Table 3.1-3 in CAISO LCTR
  - Rely on underlying data to determine effectiveness multiplying the MW of NQC by the shown resource storage duration times the Energy MWh divided by the Capacity MW
  - Adjust number of MW eligible for premium by ULR adjustment factor

Solar and wind generation: based on MW contribution of the resource type to peak period needs

Straw Proposal #2
Evaluate Shown Resources with Bid-in Resources

- Shown resource local attributes are considered alongside bids in the CPE solicitation
- Shown resources will be evaluated at the pre-determined price or the LSE may choose to show at a lower price
- CPE applies the same criteria, including effectiveness, for both shown and bid resources
- CPE may accept or reject shown resource at the price and quantity shown depending on the value relative to bid resources

LSE Elections

- Working Group tasked with determining “[w]hether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process”
- CalCCA proposes that an LSE be permitted to show in advance of the solicitation or bid into the solicitation, but not both

Existing Contract Treatment

- Working Group tasked to submit proposals on “treatment of existing contracts, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing contracts”
- Support application of the LCR RCM adopted for preferred resources to existing fossil contracts for a five-year period, provided the resources are currently online and were entered into by an LSE on or before June 11, 2020
- Consistent with the language of D.20-06-002, existing fossil UOG would be required to bid into the CPE solicitation, and bid UOG would receive CAM treatment

Other Considerations

- Resources committed through a showing would have a three-year commitment
- Term start date could be any year within the three-year forward compliance period
- Showing (like bid) documented through a confirm under the Edison Electric Institute (EEI) Master Agreement

Local Capacity Reduction Compensation Mechanism Workshop

July 27, 2020

C-40

SDGE

A Sempra Energy utility

SDG&E Proposal Based On Decision Language

"As discussed above, a hybrid model does not disincentivize procurement of local resources because LSEs procure local resources for many reasons beyond the local RA value. However, we recognize that a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas." D.20-06-002, p 40

"The Commission recognizes that a financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value would more closely align the financial compensation with the actual LCR MW reduction the resource provided." p 42

"The Commission is not open to considering a one-for-one credit, CalCCA's proposed financial credit mechanism, or a credit mechanism for fossil fuel resources (other than potentially for existing grandfathered contracts)." p 43

Resource Eligibility

The Decision identifies three types of resources as eligible to receive the LCR compensation mechanism

- Preferred resources
- Energy storage resources
- Potentially existing grandfathered fossil fuel resources

SDG&E's proposal for grandfathered fossil fuel resources is determined by the approval date of the Decision

- Contracts must be executed and/or online prior to June 11, 2020 and/or
- Resource must have been online prior to June 11, 2020

Local Premium Rate

Local Premium Rate = Weighted avg price of CPE procured resources minus NP/SP-15 MPB

One Premium Rate Per Local Area	• Limits complexity • Sub-area premiums may be calculated if data is available • Minimum number of CPE contracts in sub-area may be required
Same Premium For All Eligible Technologies	• Limits complexity
CPE Local Procurement Price	• CPE can mitigate market power by not procuring • CPE tasked to minimize procurement cost by deselecting offers that would also "show" if not elected (pp 38-39) • CPE must identify RA-only cost of tolling contract if necessary
System MPB	• Publicly available price provided by CPUC based on market transactions of LSEs

Effectiveness Factors

CAISO effectiveness factors are only published relative to a single contingency for the study process

Utilizing the published value may not yield the expected precision

SDG&E's proposal attempts to simplify the calculation that the CPE would use

- Effectiveness Factor = LCR / Total (Shown + CPE procured)
- Calculation could be further adjusted to include CAISO CPM and RMR
- Calculation may not work if Total capacity (Shown + CPE procured) < LCR

Duration of Shown Capacity

SDG&E proposal

- LSEs may show Local RA resources annually on a three year rolling basis, *i.e.* Year 0 for Years 1 - 3
- LSEs may show additional Local RA resources for the next three year rolling basis, *i.e.* Year 1 for Years 2-4
- When LCR increases for Years 2-4, LSEs should have ability to show more resources just as CPE has ability to procure more resources
- Previously shown capacity cannot be decommitted during the same time period except for certain reasons, *i.e.* retirements or force majeure
- If LSE sells shown Local RA resource to another LSE, it must notify the CPE to track the shown resource by the LSE for the same duration as before
- It may be reasonable to have a one-time election for grandfathered contracts/resources for the term of the contract which may exceed the rolling three-year Local RA program
- Effectiveness and Local Premiums are not locked in for the shown duration; both are updated with new information available

Cost Allocation Example

- Assumptions
  - CPE Procurement is $5 Million
  - Shown Local RA Premium is $10/kW-yr
  - All MWs are 100% Effective and qualify for Premium compensation

CPE Procurement	$5,000,000
Shown RA Premium ($/kW-yr)	$10
Total CPE Procurement Costs with Shown RA Premium	$8,600,000

	LSE A	LSE B	LSE C	IOU	Total
Load Ratio	10%	20%	15%	55%	100%
Shown RA (MW)	100	50	100	200	360
Shown RA Premium	$1,000,000	$500,000	$1,000,000	$2,000,000	$3,600,000
CPE Procurment Costs	$500,000	$1,000,000	$750,000	$2,750,000	$5,000,000
Total CPE Procurement Cost + Shown RA Premium	$860,000	$1,720,000	$1,290,000	$4,730,000	$8,600,000
LSE Cost Allocation net of Premium	**($140,000)**	**$1,220,000**	**$290,000**	**$2,730,000**	**$5,000,000**

APPENDIX D

AUGUST 3, 2020 INFORMAL COMMENTS

Subject: AReM's Comments on the Matrix for the LCR Reduction Compensation Mechanism
Date: Monday, August 3, 2020 at 12:34:53 PM Pacific Daylight Time
From: Sue Mara
To: Evelyn Kahl, ccsong@cleanpoweralliance.com, demerson@sonomacleanpower.org, mbrandt@ebce.org, Erica.Brown@pge.com, Rhett.Kikuyama@pge.com, Lisa.Wan@pge.com, Noelle.formosa@pge.com, s.tougas@cleanenergyregresearch.com
Attachments: MATRIX_CPE-LCR-RCM_Party-Positions-AReM's Comments.xlsx

To Co-Leads on LCR Reduction Compensation Mechanism:

Attached are AReM's comments on the matrix. Deletions are shown by strikeout and our additions are shown in red.

AReM has confined its comments to corrections regarding its July 20th comments and is not stating a position on the 7 questions posed.

Regards,

Sue Mara
On Behalf of AReM
Sue Mara
RTOAdvisors, L.L.C.
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Redwood City, CA 94062
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(415) 902-4108

Working Group on Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Treatment of Existing Contracts		
		Matrix of Parties' Positions/Preferences
No.	**Question**	**[Additional Question]**
1	How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?	Should effectiveness be determined by using the: **- CAISO's Effectiveness Factors** **- CAISO's LCTS Contribution to Peak Load Methodology** **- CAISO's LCTS Energy Storage Limitation Study** **- Other**
2	How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);	Should effectiveness adjustments be applied to the: **- Price premium** **- MW of shown capacity** **- Other**
		Should different **technology types** receive different premiums?
		Should premiums be developed at the location level: **- TAC area only** **- Local area (e.g. Bay Area)** **- Sub-local area (e.g. South Bay / Moss Landing)**
3	How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;	Should the premiums be: - **Publicly posted** - **Confidential** - **Other**
		To balance transparency and market sensitive information, how should the data be presented: **- Aggregated** - **Individual** - **Other**
		Should the premiums or effectiveness adjustments be: - **Published by the Commission** - **Other**
4	Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process;	Should the mechanism allow LSEs to: **- Bid and show** **- Bid or show** **- PG&E's proposal (if an LSE voluntarily shows, the LSE cannot select the option to both bid and voluntarily show the resource as part of the CPE's solicitation process)** **- Other**
5	How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.	Should the premium be: - **Fixed for the term of the commitment** - **Adjusted year to year** - **Other**
6	How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?	In the Workshop, parties agreed that this should be addressed in a working group or through future proposals made in the RA proceeding, as suggested by the Commission (page 53-54 of D.20-02-006)
7	In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.	What should be the **cut off date** for legacy treatment of existing contracts?
		What are the **terms (length of time)** for applying legacy treatment of existing contracts?
		What should be the **eligibility rules** for the treatment of existing contracts?
8		**Other**
9		**Overall**

[NAME OF PARTY]	Summary of Parties' Informal Comments, submitted July 20, 2020 Alliance for Retail Energy Market (AReM)	California Community Choice Association (CalCCA)
	N/A	Incorporated not through a price reduction, but into a technology-specific modification of the megawatt (MW); California Independent System Operator (CAISO) should lead a stakeholder process to develop factors that could be used.
	N/A	Price premiums would be differentiated by local areas, including the disaggregated "PG&E Other" areas, unless a higher level of aggregation were required to mask the price of individual resource prices.
	N/A	N/A
	N/A	Load serving entity (LSE) must chose to either bid or show.
	N/A	N/A
	N/A	N/A
	N/A ~~Compensation mechanism adopted for preferred resources should be applied to existing contracts entered into by an LSE before June 11, 2020; not apply to fossil utility owned generation (UOG), which will be required to bid into the solicitation.~~	N/A
		Use of a median referent price, which is unaffected by high outliers in a price distribution. Recommends that resources be committed for a three-year term; Showing, like a successful bid, should be documented through a confirm.
	1. The ability for a LSE to receive a payment from the CPE must not result in over-procurement by the CPE with the over-procurement costs spread among all LSEs. 2. The customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; they should not spread those costs to other LSEs or to the customers of other LSEs. 3. To the extent payments for shown resources are determined to be warranted, LSEs with such resource types that are worth a premium to the CPE should be eligible for compensation up to that premium. 4. The number of years of compensation for which a LSE is eligible for a LCR Reduction Compensation Mechanism payment should be for no longer than up to three years – the term of the Local RA requirement.	

California Energy Storage Alliance (CESA)	California Efficiency + Demand Management Council (Council)
Favors an approach where the central procurement entity (CPE) request for offer (RFO) considers identifying multiple portfolios of bid and shown resources that, on one end, considers effectiveness as the binding, initial screening criteria and, on the other end, more heavily considers preferred attributes while ensuring effectiveness.	Cost effectiveness of local resources should not be within the scope of the mechanism.
Generally supports granularity of the LCR reduction compensation mechanism and proposed the following premiums for consideration (1) closer-to-load, (2) Disadvantaged communities (DAC), (3) Greenhouse gas (GHG) emissions reduction and (4) market power mitigation; A one-size-fits-all premium may undercut the incremental value-add of certain projects.	Factors on which to base a premium can be resource location, resource type (especially preferred resources), or operational characteristics or for resources located in DACs.
One way to balance transparency with the need for confidentiality would be to consider base class-specific premiums that are broadly applicable to all resources within that class.	Should be as transparent as possible to ensure that resource providers can develop the products of greatest value.
LSE may bid and/or show.	N/A
Year-to-year adjustment to the local compensation mechanism should not be established and may not be needed.	N/A
CPE RFO evaluation criteria mirror the premium factors in the local compensation mechanism, link to IRP-identified future long-term procurement needs in local or sub-local areas, adhere to the loading order and SB 1136.	Both qualitative and quantitative criteria should be considered; preferred resources - favored over fossil-fuel resources and not disadvantaged, fairly compared to existing, fully-depreciated gas resources on a cost basis; greater consideration to low- or zero-emission resources in meeting State's environmental goals.
N/A	N/A

Pacific Gas and Electric Company (PG&E)	Public Advocates Office (CalPA)	Southern California Edison Company (SCE)
Local resources are not equally “effective” in meeting local area reliability needs; Should only be compensated for resources that either have been demonstrated to meet up-front eligibility requirements or have an effectiveness adjustment applied to the net qualifying capacity (NQC).	The effectiveness and ability of a resource to provide those local resource adequacy (RA) attributes should match or exceed the requirements of the Commission and/or CAISO that qualify specific technologies’ ability to count as local RA.	Local effectiveness is determined by CAISO based on the fleet of resources available and the contingencies that the fleet meets; CAISO would need to provide the information on effectiveness factors and the value of use-limited resources in meeting a local area need in its LCR studies.
Ideally, the proposed compensation mechanism would be calculated for each sub-local area; Should reflect the contribution of a resource type to local area reliability.	There should be pre-determined premiums calculated for each resource technology type.	The premium should reflect the actual contribution to the local RA need of a resource and market conditions; The level of granularity should consider, and very likely depend on, data availability and the robustness of the data that report historic RA prices for these areas.
Potential options include publishing aggregated data upfront and more granular data after a sufficient period of time has passed or publishing rankings (e.g., highest value area to lowest) or tiers with ranges (e.g., top five local premiums include these areas and are between $5 and $7).	The Commission should post the premium and include them in both its annual RA Report and the annual Final RA Guide; This may not be feasible if a premium is created for each unique resource since it may be calculated depending on market sensitive resource information.	The transparency of the premiums would depend heavily on the data used to determine the premiums.
LSE may 1) voluntarily show a resource for local premium but may not bid or 2) bid and voluntarily show the resource for no local premium.	N/A	Due to complexity, recommends this be discussed in workshops evaluating gaming risk.
Any effectiveness adjustment to local premiums should reflect the assumptions and findings of the most recent CAISO Local Capacity Technical Study Report.	Premium would increase or decrease as NQC is adjusted year to year.	Depends on details of the mechanism on how the effectiveness of resources is considered in deriving a premium.
N/A	N/A	Recommends to be addressed in the area of CPE implementation as it relates to the bid selection process and criteria.
Legacy treatment of LSE's local RA existing contracts should be applied only to contracts executed, or owned resources that were acquired, prior to issuance of D.19-02-022(3/4/2019); not to local resources procured outside of the LSE's transmission area charge (TAC) area; do not support being applied for the full term of an existing	N/A	Apply to only those existing resources signed before the issuance of central procurement decision on 3/26/2020; for new resources it could apply to contracts signed prior to the PD, therefore limitation is only for local RA contracts with existing resources - up to a five-year term length.

San Diego Gas & Electric Company (SDG&E)
Should be guided by the CAISO and the annual Local Capacity Technical Study.
Believes the complexity of developing individual premiums for the various types of resources in either sub-areas or local areas makes this task infeasible
N/A
N/A
N/A
N/A
Do not propose a separate rule for existing contracts, but not opposed to a one-time election exceeding the rolling three-year Local RA program.
Shown local RA capacity is committed for a period of up to three years; No process to decommit a resource except for certain reasons, such as resource retirements or force majeure.

Subject:	R.17-09-020 RA CalCCA Informal Comments on Compensation Mechanism
Date:	Monday, August 3, 2020 at 7:26:52 PM Pacific Daylight Time
From:	Shawn-Dai Linderman
To:	FJackson.Stoddard@MorganLewis.com, monica.schwebs@morganlewis.com, lrafii@buchalter.com, L.Tougas@CleanEnergyregresearch.com, Maria@OhmConnect.com, NicholasC@AdvMicrogrid.com, Shagun Tougas, AnnaFero@dwt.com, TBrunello@Calstrat.com, Buck.Endemann@KLGates.com, jmcintyre@goodinmacbride.com, KatieJorrie@dwt.com, MSomogyi@GoodinMacBride.com, nsikand@goodinmacbride.com, Tara.Kaushik@HKlaw.com, DWTcpucDockets@dwt.com, Allie@Reimagine-Power.com, steven@moss.net, james@voltus.co, mplante@voltus.co, charles.middlekauff@pge.com, SSMyers@att.net, RegRelcpucCases@pge.com, Debra.Lloyd@CityofPaloAlto.org, fwahl@tesla.com, Nathanael Miksis, Pushkar Wagle, MikeMoore315@Yahoo.com, Emmie@elsysinc.com, BarmackM@calpine.com, galamberg@petersonpower.com, SArora@LSpower.com, Sarah.Qureshi@NextEraEnergy.com, AHarron@HarronLLC.com, Cynthia.Clark@UCOP.edu, sberelson@cedmc.org, jeddy@opiniondynamics.com, Katherine.Ramsey@SierraClub.org, policy@cedmc.org, RBird@BorregoSolar.com
Attachments:	R.17-09-020 CalCCA Informal Comments on Compensation Mechanism 8_3_20.pdf, R.19-11-009 SL CalCCA Informal Comments on Compensation Mechanism.pdf

To Service Lists for R.17-09-020 and R.19-11-009:

Attached please find the **CALIFORNIA COMMUNITY CHOICE ASSOCIATION INFORMAL COMMENTS ON THE LOCAL CAPACITY REDUCTION COMPENSATION MECHANISM.** This document is being served by electronic mail in word-searchable PDF format.

This service is being sent in multiple parts.

Thank you.

Shawn-Dai Linderman
Policy Assistant
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To keep up with CCA news subscribe to our mailing list here.
You can also follow CalCCA on Twitter and LinkedIn.

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
INFORMAL COMMENTS ON THE LOCAL CAPACITY REDUCTION COMPENSATION MECHANISM

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August 3, 2020

Table of Contents

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
INFORMAL COMMENTS ON LCR COMPENSATION MECHANISM

The California Community Choice Association (CalCCA)[1] submits these informal comments on the issues identified in Decision (D.) 20-06-002 to update and summarize its proposal for designing the Resource Adequacy (RA) Central Procurement Entity (CPE) Local Capacity Requirement (LCR) Reduction Compensation Mechanism (RCM). CalCCA's initial proposal, presented in its July 20 informal comments, has evolved through discussions with other parties individually and in the July 27 workshop. Based on workshop feedback, CalCCA has narrowed its proposal to focus on one of the options included in its initial comments. These comments (1) discuss the challenges presented in designing an RCM around the principles discussed in D.20-06-002; (2) present responses to the questions directly posed by the Commission for the WG; and (3) summarize CalCCA's overall proposal.

I. INTERPRETING D.20-06-002

Discussions among the parties at the workshop raised questions regarding the boundaries prescribed by the Commission for RCM design. CalCCA thus identifies Commission directives on key issues and some of the challenges in integrating these directives.

For reference, CalCCA lists below the directives of D.20-06-002 relevant to RCM design.

Effectiveness:

1. The RCM cannot provide a "one for one" premium as CalCCA proposed without considering effectiveness. [p.41]

2. The RCM must address "local effectiveness" and "use limitations" of the shown resource…. [O¶ 5.d.]

3. The WG should consider how to adjust payments to an LSE "from year to year to account for changes in the effectiveness of the resource reducing local requirements." [O¶ 5.d.]

---

[1] California Community Choice Association represents the interests of 20 operational 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 José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

4. CPE selection criteria must include (1) “Local effectiveness factors, as published in the California Independent System Operator’s Local Capacity Requirement Technical Studies” [O¶ 14.b.] and “Energy-use limitations” [O¶ 14.h.]

Least-Cost, Best-Fit:

5. “Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSEs seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE” [p. 42 and O¶ 5.d.]

6. “[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources” [p. 42]

Premium Determination:

7. The RCM should “only compensate[] LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs” [p.43]

8. “[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources” [p. 42]

9. A “benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums” [p.42]

10. “[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources” [p. 42]

11. The WG must determine “[h]ow to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices.” [O¶ 5.b.]

In addition to these directives, the Commission rejected CalCCA’s proposal for a one-for-one credit with ex post pricing based on the average price paid by the CPE for resources in the local area for which a resource is shown. It directed that “[a]n ‘LCR reduction compensation mechanism’ departs from CalCCA’s must-take, local price based proposal.” [p. 43] CalCCA interprets this directive as foreclosing reliance on: an ex post price; an average of bid prices accepted by the CPE; and a premium that ignores effectiveness and use limitations.

From these conclusions, CalCCA gleaned the boundaries to guide its proposal. The RCM must (i) have a pre-determined, rather than ex post, price premium; (ii) account for "local effectiveness" and "use limitations"; (iii) avoid the influence of "market power inflated price premiums"; and (iv) compare the premium "alongside" bid resources to evaluate the overall cost effectiveness of the CPE portfolio. While the Commission indicated that the premium "may" be cost-based, it did not foreclose a market-based premium.

CalCCA worked within these boundaries despite certain challenges, some of which are discussed below. A foundational principle, however, lacks clarity. D.20-06-002 did not make clear whether shown resources, even after adjusting for effectiveness and use limitations, would be "must take" or whether they could be rejected by the CPE if the RCM formula did not result in the most cost-effective CPE portfolio. While the Commission did not foreclose a must-take structure *provided* that it accounts for effectiveness and use limitations, CalCCA's proposal nonetheless takes the most conservative reading of the decision: the CPE may reject a shown resource on cost effectiveness grounds. This approach gives more weight to the importance of a least-cost, best-fit portfolio and ratepayer value and substantially simplifies implementation.

II. RESPONSES TO D.20-06-002 QUESTIONS

1. How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?

Addressing effectiveness and use limitations was one of the most difficult challenges in designing an RCM. As discussed in CalCCA's July 20 comments, D.20-06-002 essentially asked the WG to develop a methodology that neither the CAISO nor the Commission, to date, has been able to develop. CalCCA nonetheless framed two approaches to assessing these factors, which were presented at the workshop and are discussed below. Critically, however, CalCCA's proposal summarized in Section IV does *not* require an express determination on either factor; instead, it relies on the CPE to assess them in evaluating the shown resource's value. Whatever methodology the CPE applies to bid resources to assess effectiveness and use limitations will be equally applied to shown resources.

a. Methodologies Considered by CalCCA

CalCCA presented two possible methodologies at the workshop to evaluate effectiveness and use limitations. Both methodologies, however, require substantial additional development to implement and, even then, will provide only very rough justice.

Method 1: CAISO Local Effectiveness Factors

D.20-06-002 directs the CPE must consider in selecting resources in its solicitation the local effectiveness factors found in the California Independent System Operator (CAISO) Local Capacity Technical Report and Operating Procedure 2210Z. [O¶ 14.h.] These factors are stated as a percentage effectiveness for each existing resource in a local area. One approach thus would be to apply these factors, stated in percentages, to reduce the MW of shown capacity. The reduction would need to be scaled; CalCCA considered scaling the shown resource's factor to the average of the factors for resources selected by the CPE in a local area.

While CalCCA believes that this approach could be used to provide some indication of the relative value of shown vs. bid resources, no party advocates using this approach. CalCCA believes that it would require development of potentially rigid selection criteria that may not align with the criteria needed for the CPE to assess the value of both shown and bid resources. In short, CalCCA does not believe this is approach would produce reasonable premiums. The CAISO has made clear, several times, that the published factors were not intended to be used in this manner. Indeed, the published factors represent a resource's effectiveness in resolving the "highest" constraint in the area, among potentially dozens of constraints. So, for example, one resource might be highly effective in addressing the top constraint but completely ineffective in addressing another, and another might not be effective in addressing the top constraint but is highly effective in addressing 19 other constraints. Relying on the published factors would give full credit to the first resource and no credit to the other resource –an incomplete and inequitable result. In fact, as one IOU commenter noted during the July 27 workshop, it is highly unlikely that the CPE will apply these factors quantitatively but will consider them qualitatively among other resource characteristics. Reliance on CAISO's published effectiveness factors to scale the shown resource MW will not fully or fairly represent a resource's locational value.

Method 2: Addressing Use Limitations

CalCCA also considered a technology-specific approach to address use limitations. The CPE could develop a factor for battery storage by comparing the battery storage duration of the shown resource to the duration of the resources selected by the CPE in the local area. If the CPE selected any four-hour batteries in an area, a four-hour shown battery would receive 100% credit. Alternatively, if the CPE selected no four-hour batteries in an area, the CAISO LCTR provides other potential avenues of assessing battery use limitations, including the data underlying LCTR Table 3.1-3 to compare a shown resource's storage duration to the CAISO-determined storage duration required in the local area. This approach, however, requires a consideration of the baseline underlying those required durations and interpretation of the overall data. Implementation, if possible, would require additional time and might in the end provide only rough justice to a shown resource.

A different approach would be needed for solar, wind, and hydro generation. PG&E identified, and CalCCA considered, relying on the LCTR's assessment in each local area of a resource type's contribution to the peak hour in the area. For example, PG&E pointed to the CAISO's assessment of the Sierra LCR area load and resources. [LCTR p. 42] The LCTR states that the "estimated time of local area peak is 19:10 PM," and ISO-metered solar output at the time is 2.0 percent. While the methodology was not discussed in detail, presumably PG&E intended to multiply storage MW of capacity in the Sierra area by 2 percent to adjust the MW to which the premium price would be applied. Unfortunately, this information is not provided for all local areas (*see, e.g.,* North Coast and North Bay LCR, p. 32). Further, this approach would not apply to wind and hydro resources, and separate methodologies would need to be developed.

Overall, a piecemeal approach to evaluating use limitations might be possible. Additional development would be required, however, and the result, again, would provide only rough justice to shown resources.

b. CalCCA Proposed Approach

CalCCA proposes that shown resources be compared for selection by the CPE alongside bid resources, subject to a pre-determined price cap, to ensure a least cost, best fit solution. Consequently, neither the premium nor the MW shown would be discounted. Like bids, if the CPE selects the resource, the resource owner will get the pre-determined price for the MW of NQC provided; if the CPE rejects the bid, the resource owner will get nothing. CalCCA's proposal thus leaves the question of how to evaluate effectiveness and use limitations to the CPE's process used for bid resources. As long as the CPE applies its selection criteria for both shown and bid resources in a non-discriminatory manner, LSEs can use the showing mechanism to make their local resources available to the CPE without having to participate in the CPE solicitation process.

2. How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas)?

CalCCA proposes a premium for each local area or sub-area to ensure that the shown resources are reasonably valued and have a reasonable opportunity to "compete" with bid resources in the same local area. The premium would be set at a more aggregated level if required to mask prices of individual resources.

CalCCA's proposal makes any other granularity, such as technology, unnecessary. The CPE will consider all of these factors in evaluating both shown and bid resources using the criteria mandated by the Commission for selecting resources from the solicitation.

3. How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices.

CalCCA proposes development of a premium that will be published annually. The premium would be calculated as follows:

> Year 1: Use the median price from the last two quarters of Energy Division PCIA responses for both system and local RA; subtract system price from local RA price and multiply by effective MW
>
> Subsequent Years: Use the median price from the last two quarters of Energy Division PCIA responses for system RA and the most reported CPE solicitation results for local RA price; subtract system RA price from local RA price and multiply by effective MW

There would be little risk to the market of publishing the premiums determined using this methodology. The system prices ultimately will be published within a year in the annual Energy Division RA Report, so there is little or no risk in revealing these prices. Making the median CPE price in the prior solicitation public also presents little risk. The median reveals nothing about the stratification of bids around the median, nor does it illuminate bid prices for bundled system/local RA resources.

4. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process.

CalCCA proposes that an LSE must choose between the bid and show options. Allowing a resource to show a resource at the pre-determined price but later revoke its showing if it is able to do better in the bid solicitation process is difficult to rationalize. Why would the CPE choose a resource in the bid process that has been made available through showing if the bid price is higher than the pre-determined price? To make this choice would be contrary to ratepayers' interests. Conversely, why would an LSE ask for less in the solicitation than it could otherwise garner through a showing? Even aside from these complications, allowing an LSE to both bid and show would require further implementation rules regarding the timing and sequencing of these elections. For these reasons, the Commission should reject the bid *and* show approach.

PG&E has proposed a variant of this approach: if an LSE chooses to show but not bid, it may receive the local premium at the pre-determined price; if an LSE bids and later shows when not selected in the solicitation process, the LSE may do so but may not receive the local premium. While there is a reasonable basis, from a ratepayer value standpoint, to adopt this approach, it creates questions around the CPE solicitation. If the CPE knows in advance that the LSE will show at no cost if its bid is not selected, why would the CPE under any circumstances select the bid? From a ratepayer standpoint, it would add unnecessary cost. This approach, however, could distort the bid solicitation process and create conditions that disadvantage non-LSE bidders.

5. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

As with other questions, CalCCA's proposal simplifies the response to this question. The CPE is highly unlikely to adjust bid prices from year to year for resources selected in the solicitation. It will pay the price bid for the term proposed or it will reject the bid; the notion of accepting a bid subject to future modification is antithetical to the normal IOU solicitation process. Likewise, since the CPE will be comparing the shown resources alongside the bid resources, the same principle should apply. Either the CPE accepts the resource at the price and term shown, or it rejects the resource; there is no right to modify in the future as effectiveness changes. In short, there is no need under CalCCA's proposal to develop an annual effectiveness adjustment for shown resources.

6. How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?

This question seems unrelated to the working group's purpose and should be addressed holistically in the development of the CPE's bid evaluation criteria. CalCCA observes, however, that if a gas and preferred resource produce roughly equal value in all respects (a highly unlikely scenario), the CPE should be bound to select the preferred resource.

7. In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.

CalCCA proposes to provide the premium to LSEs who have shown their existing local RA attributes to the CPE. "Existing contracts" should be defined as contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued). The premium should be provided for the lesser of the remaining contract term and the end of the 2025 RA compliance year.

The IOUs propose to grant eligibility to utility-owned generation (UOG) under the "existing contract" provision. Their proposal falls unambiguously outside of the intent of D.20-06-002. CalCCA's interpretation of the decision rests on the following Commission directives:

- "For existing local contracts, including gas contracts, a working group process is established in Section 3.5 to consider treatment of these existing contracts." [p. 41]
- "The working group should submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed LCR reduction compensation mechanism should be applied to existing contracts." [p. 46]
- "The working group directed in Ordering Paragraph 5 shall also consider and submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing contracts." [O¶ 6.]

The decision, in other contexts, distinguished IOU UOG and contracts. It stated: "[i]t is also reasonable for the IOU to bid its resources into the CPE's RFO, including utility-owned generation (UOG) or contractually committed resources that are not already allocated to all benefitting customers, at their levelized fixed costs, and we direct the utility to do so when it is acting as the CPE." [p. 48]

The Commission also set clear parameters on the choices an IOU has for its resources. It directed: "A distribution utility acting as the CPE should bid its own resources into the solicitation process at their levelized fixed costs." It also specified: "A distribution utility shall have the same options as other load-serving entities in deciding whether to bid or show its resources into the central procurement entity's solicitation process." [COL 14.] In other words, the IOU will be able to show its preferred resources or energy storage to the CPE, just as other LSEs. The IOUs should also be able to show existing fossil contracts, subject to the terms and conditions discussed in CalCCA's proposal above.

III. OTHER DESIGN ISSUES

D.20-06-002 did not address the term of a resource showing. CalCCA proposes that LSEs be permitted to show for up to whatever term is allowed for bid resources, recognizing that the term it shows will affect the CPE's evaluation of its value. The term start date could be any year within the three-year forward CPE compliance period.

CalCCA also proposes requiring a showing, like a bid, to be documented through a confirm under the Edison Electric Institute (EEI) Master Agreement. Shown resources should have the same level of commitment to the CPE as any bid resource.

IV. SUMMARY OF CALCCA PROPOSAL

In response to the presentations and discussion at the July 27 workshop, CalCCA proposes the following framework for the RCM.

Shown Resources Compared Alongside Bid Resources	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources
Annual Price Update	If selected, LSE will be paid the pre-determined price for the shown resource without annual adjustment for effectiveness
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose
Calculation of Payment	If selected, LSE will be paid the pre-determined price for the shown resource
Premium Granularity	Local area or sub-area unless aggregation up is required to mask individual resource prices
Showing Term	LSE may show a resource for a term of up to three years, with the term commencing within the current three-year compliance period
Bid/Show Election	LSE may show or bid its resource, not both
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show for the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing “resources” do not qualify for a local showing.

Subject: RE: [RA - LCR RCM Working Group] Matrix and Presentations
Date: Monday, August 3, 2020 at 8:47:20 AM Pacific Daylight Time
From: Matthew Barmack
To: Wan, Lisa, Shagun Tougas
Attachments: Copy of MATRIX_CPE-LCR-RCM_Party-Positions_CPN.xlsx

This email constitutes Calpine's informal comments. In addition, am attaching a partially completed version of the matrix. Hope that you are the relevant representatives of the co-leads. LMK if I should direct this email elsewhere.

Calpine believes that CalCCA's Straw Proposal #2 (as articulated on slide 13 of CalCCA's July 27th working group presentation) warrants further exploration. As Calpine understands it, under the proposal, shown resources would be compared to bid resources in CPE solicitations. In CPE solicitations, shown resources would be treated as bids (for an unbundled local attribute) at pre-specified premiums that would reflect the locations and operating characteristics of the resources. LSEs also would have the option to have their shown resources treated as bids at prices below the relevant pre-specified premiums.

The proposal provides a coherent mechanism to ensure that shown and bid resources are compared using the same criteria and that the ultimate selection of the combination of shown and bid resources to meet local RA requirements is reasonably efficient. In addition, based on the presentations and discussions at the July 27th workshop, it seems like it will be difficult to develop pre-specified premiums that accurately reflect the local RA value of different resources with sufficient granularity. The proposal minimizes the importance of the premiums because it would not require the CPE to pay the premiums for shown resources if more economic alternatives were available. In addition, it provides LSEs flexibility to make local attributes available to the CPE at prices other than the pre-specified premiums.

Calpine has two general comments on the proposal:

First, given that the CPE would be able to compare shown and bid resources in the solicitation, it is unclear why it would be necessary to establish pre-specified premiums for shown resources. Instead, if the proposal is ultimately adopted, the Commission should consider giving LSEs full flexibility to specify the prices at which shown resources will be compared to bid resources in the CPE solicitations recognizing that this structure would provide LSEs incentives to offer competitively to ensure that their resources are selected over offered resources and that the CPE would have the discretion to not "procure" shown resources and defer to CAISO backstop procurement in the absence of sufficient competition.

Second, the Commission might consider a similar option to offer unbundled local attributes into the CPE solicitations for all supply, not only shown capacity. If the CPE solicitations are structured to accommodate what are essentially bids for unbundled local attributes for shown capacity, it is unclear why that functionality should be limited to shown capacity.

Calpine recognizes that the two preceding tweaks could be inconsistent with the CPE decision but believes that they could be implemented through a PTM or new decision.

These and other concerns are reflected in the attached matrix.

Thank you for your consideration.

From: Wan, Lisa <L2WG@pge.com>

Sent: Thursday, July 30, 2020 3:14 PM
To: Evelyn Kahl <evelyn@cal-cca.org>; 'ccsong@cleanpoweralliance.com' <ccsong@cleanpoweralliance.com>; demerson@sonomacleanpower.org; mbrandt@ebce.org; Brown, Erica <e1ba@pge.com>; Kikuyama, Rhett <R2K3@pge.com>; Wan, Lisa <L2WG@pge.com>; Formosa, Noelle (Law) <NRF6@pge.com>
Cc: Nickerman, Luke <LxNg@pge.com>; erdal.kara@vistraenergy.com; csanada@caiso.com; Rybka, Greg <GMRA@pge.com>; skeehn@mbcp.org; patrick.cunningham@cpuc.ca.gov; samk@pioneercommunityenergy.ca.gov; william.rostov@sfcityatty.org; ckeys@peninsulacleanenergy.com; jennifer.chamberlin@cpowerenergymanagement.com; john.leslie@dentons.com; rachel.mcmahon@sunrun.com; david.vidaver@energy.ca.gov; linnan.cao@cpuc.ca.gov; jose.torrebueno@cc-energy.org; peter.mcferrin@sce.com; rmiller3@sdge.com; jonathan.lakey@cpuc.ca.gov; brian@pacificea.com; christine.powell@cpuc.ca.gov; cathy.karlstad@sce.com; agregory@pilotpowergroup.com; Ashley Lewis Bernstein <Ashley.Bernstein@calpine.com>; amsmith@sdge.com; cgrinstead@cleanpoweralliance.org; msusko@ebce.org; Matthew Barmack <Matthew.Barmack@calpine.com>; ntang@sdge.com; jabari.martin@sce.com; btheaker@mrpgenco.com; mary.lynch@constellation.com; amaani@leap.ac; wei.zhou@sce.com; jnoh@storagealliance.org; l.tougas@cleanenergyregresearch.com; beth@cal-cca.org; asoe@sdge.com; steve.greenleaf@brookfieldrenewable.com; philm@scdenergy.com; amorris@storagealliance.org; michael.evans@shell.com; hgao@sdge.com; bsb@eslawfirm.com; sue.mara@rtoadvisors.com; cchase@sdge.com; sduenas@storagealliance.org; jaimerose.gannon@cpuc.ca.gov; tyson@protectourcommunities.org; tbrunello@calstrat.com; lgarcia-rodriguez@sdge.com; klatt@energyattorney.com; mark.hesters@energy.ca.gov; carleigh@ceert.org; cbriggs@eslawfirm.com; acissna@redwoodenergy.org; ad1@cpuc.ca.gov; malcolm.ainspan@nrg.com; gcontreras@wellhead.com; kyle.navis@cpuc.ca.gov; Griffes, Peter <PHG3@pge.com>; ska@cpuc.ca.gov; emoussa@sdge.com; eric.little@sce.com; dougbocc@flynnrci.com
Subject: [RA - LCR RCM Working Group] Matrix and Presentations

External Sender: Use caution with links/attachments.

All,

Attached, please find the presentations from the Monday 7/27 *Working Group Workshop on Local Capacity Requirement Reduction*
Compensation Mechanism and Treatment of Existing Contracts and the Matrix on Party Positions.

For the Matrix on Party Positions, please note the following:

- Please provide your organization's position or preferences for the issues laid out in the matrix. Please fill out the light orange column and note the name of your organization.
- Please send the matrix back to the co-leads on Monday 8/3. This is the same day as when the informal comments on the workshop to co-leads are due.
- For our reference, the co-leads have included a summary of the informal comments submitted Monday 7/20. If there are any misstatements, please make any necessary edits and let us know.
- If you'd like to provide a summary of your Monday 8/3 comments in the matrix, please feel free to do so.

If you have any questions, please feel free to reach out to me (lisa.wan@pge.com) or Shagun Tougas (s.tougas@cleanenergyregresearch.com).

Thank you,

Lisa Wan
PG&E | Regulatory Affairs
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Email: lisa.wan@pge.com

Working Group on Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Treatment of Existing Contracts

Matrix of Parties' Positions/Preferences

No.	Question	[Additional Question]	Calpine
1	How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?	Should effectiveness be determined by using the: **- CAISO's Effectiveness Factors** **- CAISO's LCTS Contribution to Peak Load Methodology** **- CAISO's LCTS Energy Storage Limitation Study** **- Other**	Calpine believes that the mechanism should consider effectiveness related to the effectiveness factors that are included in the LCTS as well as duration/energy limits analyzed by the CAISO.
2	How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);	Should effectiveness adjustments be applied to the: **- Price premium** **- MW of shown capacity** **- Other**	Either an adjustment to the price premium or the MW credited could work.
		Should <u>different</u> **technology types** receive <u>different</u> premiums?	Different technologies should receive different credits with respect to their "effectiveness" as defined in response to question 1.
		Should premiums be developed at the location level: **- TAC area only** **- Local area (e.g. Bay Area)** **- Sub-local area (e.g. South Bay / Moss Landing)**	Premiums should reflect the fact that resources in different locations, including different sub-areas, have different "effectiveness."
3	How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;	Should the premiums be: - **Publicly posted** - **Confidential** - **Other**	As indicated in Calpine's informal comments, Calpine believes that CalCCA's Straw Proposal #2 warrants further exploration. Under this approach, given that the CPE would be able to compare shown and bid resources in the solicitation, it is unclear why it would be necessary to establish pre-specified premiums for shown resources. Instead, if the proposal is ultimately adopted, the Commission should consider giving LSEs full flexibility to specify the prices at which shown resources will be compared to bid resources in the CPE solicitations recognizing that this structure would provide LSEs incentives to offer competitively to ensure that their resources are selected over offered resources and that the CPE would have the discretion to not "procure" shown resources and defer to CAISO backstop procurement in the absence of sufficient competition.
		To balance transparency and market sensitive information, how should the data be presented: **- Aggregated** **- Individual** - **Other**	
		Should the premiums or effectiveness adjustments be: **- Published by the Commission** - **Other**	
4	Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process;	Should the mechanism allow LSEs to: **- Bid and show** **- Bid or show** **- PG&E's proposal (if an LSE voluntarily shows, the LSE cannot select the option to both bid and voluntarily show the resource as part of the CPE's solicitation process)** **- Other**	
5	How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.	Should the premium be: - **Fixed for the term of the commitment** - **Adjusted year to year** - **Other**	If something like CalCCA's Straw Proposal #2 were adopted, presumably shown resources would have the same certainty with respect to compensation as resources that are offered directly into the CPE solictations, i.e., if the "bid" associated with a shown resource were selected, it would be paid its bid for the term of the commitment for which it was selected.
6	How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?	In the Workshop, parties agreed that this should be addressed in a working group or through future proposals made in the RA proceeding, as suggested by the Commission (page 53-54 of D.20-02-006)	
7	In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.	What should be the **cut off date** for legacy treatment of existing contracts?	
		What are the **terms (length of time)** for applying legacy treatment of existing contracts?	
		What should be the **eligibility rules** for the treatment of existing contracts?	
8		**Other**	
9		**Overall**	See informal comments.

Summary of Parties' Informal Comments, submitted July 20, 2020			
Alliance for Retail Energy Market (AReM)	**California Community Choice Association (CalCCA)**	**California Energy Storage Alliance (CESA)**	**California Efficiency + Demand Management Council (Council)**
N/A	Incorporated not through a price reduction, but into a technology-specific modification of the megawatt (MW); California Independent System Operator (CAISO) should lead a stakeholder process to develop factors that could be used.	Favors an approach where the central procurement entity (CPE) request for offer (RFO) considers identifying multiple portfolios of bid and shown resources that, on one end, considers effectiveness as the binding, initial screening criteria and, on the other end, more heavily considers preferred attributes while ensuring effectiveness.	Cost effectiveness of local resources should not be within the scope of the mechanism.
N/A	Price premiums would be differentiated by local areas, including the disaggregated "PG&E Other" areas, unless a higher level of aggregation were required to mask the price of individual resource prices.	Generally supports granularity of the LCR reduction compensation mechanism and proposed the following premiums for consideration (1) closer-to-load, (2) Disadvantaged communities (DAC), (3) Greenhouse gas (GHG) emissions reduction and (4) market power mitigation; A one-size-fits-all premium may undercut the incremental value-add of certain projects.	Factors on which to base a premium can be resource location, resource type (especially preferred resources), or operational characteristics or for resources located in DACs.
N/A	N/A	One way to balance transparency with the need for confidentiality would be to consider base class-specific premiums that are broadly applicable to all resources within that class.	Should be as transparent as possible to ensure that resource providers can develop the products of greatest value.
N/A	Load serving entity (LSE) must chose to either bid or show.	LSE may bid and/or show.	N/A
N/A	N/A	Year-to-year adjustment to the local compensation mechanism should not be established and may not be needed.	N/A
N/A	N/A	CPE RFO evaluation criteria mirror the premium factors in the local compensation mechanism, link to IRP-identified future long-term procurement needs in local or sub-local areas, adhere to the loading order and SB 1136.	Both qualitative and quantitative criteria should be considered; preferred resources - favored over fossil-fuel resources and not disadvantaged, fairly compared to existing, fully-depreciated gas resources on a cost basis; greater consideration to low- or zero-emission resources in meeting State's environmental goals.
Compensation mechanism adopted for preferred resources should be applied to existing contracts entered into by an LSE before June 11, 2020; not apply to fossil utility owned generation (UOG), which will be required to bid into the solicitation.	N/A	N/A	N/A
	Use of a median referent price, which is unaffected by high outliers in a price distribution. Recommends that resources be committed for a three-year term; Showing, like a successful bid, should be documented through a confirm.		
The ability for a LSE to receive a payment from the CPE must not result in over-procurement by the CPE with the over-procurement costs spread among all LSEs. The customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; they should not spread those costs to other LSEs or to the customers of other LSEs.			

Pacific Gas and Electric Company (PG&E)	Public Advocates Office (CalPA)	Southern California Edison Company (SCE)	San Diego Gas & Electric Company (SDG&E)
Local resources are not equally "effective" in meeting local area reliability needs; Should only be compensated for resources that either have been demonstrated to meet up-front eligibility requirements or have an effectiveness adjustment applied to the net qualifying capacity (NQC).	The effectiveness and ability of a resource to provide those local resource adequacy (RA) attributes should match or exceed the requirements of the Commission and/or CAISO that qualify specific technologies' ability to count as local RA.	Local effectiveness is determined by CAISO based on the fleet of resources available and the contingencies that the fleet meets; CAISO would need to provide the information on effectiveness factors and the value of use-limited resources in meeting a local area need in its LCR studies.	Should be guided by the CAISO and the annual Local Capacity Technical Study.
Ideally, the proposed compensation mechanism would be calculated for each sub-local area; Should reflect the contribution of a resource type to local area reliability.	There should be pre-determined premiums calculated for each resource technology type.	The premium should reflect the actual contribution to the local RA need of a resource and market conditions; The level of granularity should consider, and very likely depend on, data availability and the robustness of the data that report historic RA prices for these areas.	Believes the complexity of developing individual premiums for the various types of resources in either sub-areas or local areas makes this task infeasible
Potential options include publishing aggregated data upfront and more granular data after a sufficient period of time has passed or publishing rankings (e.g., highest value area to lowest) or tiers with ranges (e.g., top five local premiums include these areas and are between $5 and $7).	The Commission should post the premium and include them in both its annual RA Report and the annual Final RA Guide; This may not be feasible if a premium is created for each unique resource since it may be calculated depending on market sensitive resource information.	The transparency of the premiums would depend heavily on the data used to determine the premiums.	N/A
LSE may 1) voluntarily show a resource for local premium but may not bid or 2) bid and voluntarily show the resource for no local premium.	N/A	Due to complexity, recommends this be discussed in workshops evaluating gaming risk.	N/A
Any effectiveness adjustment to local premiums should reflect the assumptions and findings of the most recent CAISO Local Capacity Technical Study Report.	Premium would increase or decrease as NQC is adjusted year to year.	Depends on details of the mechanism on how the effectiveness of resources is considered in deriving a premium.	N/A
N/A	N/A	Recommends to be addressed in the area of CPE implementation as it relates to the bid selection process and criteria.	N/A
Legacy treatment of LSE's local RA existing contracts should be applied only to contracts executed, or owned resources that were acquired, prior to issuance of D.19-02-022(3/4/2019); not to local resources procured outside of the LSE's transmission area charge (TAC) area; do not support being applied for the full term of an existing	N/A	Apply to only those existing resources signed before the issuance of central procurement decision on 3/26/2020; for new resources it could apply to contracts signed prior to the PD, therefore limitation is only for local RA contracts with existing resources - up to a five-year term length.	Do not propose a separate rule for existing contracts, but not opposed to a one-time election exceeding the rolling three-year Local RA program.
			Shown local RA capacity is committed for a period of up to three years; No process to decommit a resource except for certain reasons, such as resource retirements or force majeure.

Subject:	RE: [RA - LCR RCM Working Group] Matrix and Presentations
Date:	Monday, August 3, 2020 at 5:04:27 PM Pacific Daylight Time
From:	l.tougas@cleanenergyregresearch.com
To:	'Evelyn Kahl', ccsong@cleanpoweralliance.com, demerson@sonomacleanpower.org, mbrandt@ebce.org, 'Brown, Erica', 'Kikuyama, Rhett', 'Formosa, Noelle (Law)'
CC:	'Wan, Lisa', 'Shagun Tougas'
Attachments:	MATRIX_CPE-LCR-RCM_Party-Positions - CEDMC.xlsx

Hello,

See attached the Council's completed matrix. Please note that we have made some clarifications in red font to the summary of the Council's responses to the initial questions. If you have any questions, please don't hesitate to contact me.

Thank you and have a good evening.

Best regards,

Luke

Luke Tougas
Clean Energy Regulatory Research (CERR)
l.tougas@cleanenergyregresearch.com | 510.326.1931
Website | LinkedIn | Twitter

From: Wan, Lisa <L2WG@pge.com>
Sent: Thursday, July 30, 2020 3:14 PM
To: Evelyn Kahl <evelyn@cal-cca.org>; 'ccsong@cleanpoweralliance.com' <ccsong@cleanpoweralliance.com>; demerson@sonomacleanpower.org; mbrandt@ebce.org; Brown, Erica <e1ba@pge.com>; Kikuyama, Rhett <R2K3@pge.com>; Wan, Lisa <L2WG@pge.com>; Formosa, Noelle (Law) <NRF6@pge.com>
Cc: Nickerman, Luke <LxNg@pge.com>; erdal.kara@vistraenergy.com; csanada@caiso.com; Rybka, Greg <GMRA@pge.com>; skeehn@mbcp.org; patrick.cunningham@cpuc.ca.gov; samk@pioneercommunityenergy.ca.gov; william.rostov@sfcityatty.org; ckeys@peninsulacleanenergy.com; jennifer.chamberlin@cpowerenergymanagement.com; john.leslie@dentons.com; rachel.mcmahon@sunrun.com; david.vidaver@energy.ca.gov; linnan.cao@cpuc.ca.gov; jose.torrebueno@cc-energy.org; peter.mcferrin@sce.com; rmiller3@sdge.com; jonathan.lakey@cpuc.ca.gov; brian@pacificea.com; christine.powell@cpuc.ca.gov; cathy.karlstad@sce.com; agregory@pilotpowergroup.com; ashley.bernstein@calpine.com; amsmith@sdge.com; cgrinstead@cleanpoweralliance.org; msusko@ebce.org; barmackm@calpine.com; ntang@sdge.com; jabari.martin@sce.com; btheaker@mrpgenco.com; mary.lynch@constellation.com; amaani@leap.ac; wei.zhou@sce.com; jnoh@storagealliance.org; l.tougas@cleanenergyregresearch.com; beth@cal-cca.org; asoe@sdge.com; steve.greenleaf@brookfieldrenewable.com; philm@scdenergy.com; amorris@storagealliance.org; michael.evans@shell.com; hgao@sdge.com; bsb@eslawfirm.com; sue.mara@rtoadvisors.com; cchase@sdge.com; sduenas@storagealliance.org; jaimerose.gannon@cpuc.ca.gov; tyson@protectourcommunities.org; tbrunello@calstrat.com; lgarcia-rodriguez@sdge.com; klatt@energyattorney.com; mark.hesters@energy.ca.gov; carleigh@ceert.org; cbriggs@eslawfirm.com; acissna@redwoodenergy.org; ad1@cpuc.ca.gov; malcolm.ainspan@nrg.com; gcontreras@wellhead.com; kyle.navis@cpuc.ca.gov; Griffes, Peter <PHG3@pge.com>; ska@cpuc.ca.gov;

emoussa@sdge.com; eric.little@sce.com; dougbocc@flynnrci.com
Subject: [RA - LCR RCM Working Group] Matrix and Presentations

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Thank you,

Lisa Wan
PG&E | Regulatory Affairs
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Working Group on Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Treatment of Existing Contracts			
	Matrix of Parties' Positions/Preferences		
No.	**Question**	**[Additional Question]**	**California Efficiency + Demand Management Council**
1	How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?	Should effectiveness be determined by using the: **- CAISO's Effectiveness Factors** **- CAISO's LCTS Contribution to Peak Load Methodology** **- CAISO's LCTS Energy Storage Limitation Study** **- Other**	The Council does not support the use of any of these approaches for determining local effectiveness. The concept of resource-specific local effectiveness has not been addressed by the CPUC which should be done before applying it in this context.
2	How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);	Should effectiveness adjustments be applied to the: **- Price premium** **- MW of shown capacity** **- Other**	N/A
		Should <u>different</u> **technology types** receive <u>different</u> premiums?	Not withstanding the Council's opposition to the use of local effectiveness factors, premiums should not be technology-specific. Using demand response as an example, whether the underlying technology is energy storage or customer load is irrelevant. Furthermore, the Loading Order, which serves as the basis for the CPUC's directive to favor preferred resources in CPE procurement, does not differentiate between technology types for renewables, demand response, or energy efficiency.
		Should premiums be developed at the location level: **- TAC area only** **- Local area (e.g. Bay Area)** **- Sub-local area (e.g. South Bay / Moss Landing)**	Locational premiums should only be applied at the subLAP or LCA level.
3	How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;	Should the premiums be: - **Publicly posted** - **Confidential** - **Other**	Premiums should be publicly posted for transparency and to promote the development of resources that are most highly valued.
		To balance transparency and market sensitive information, how should the data be presented: - **Aggregated** - **Individual** - **Other**	N/A
		Should the premiums or effectiveness adjustments be: - **Published by the Commission** - **Other**	Premiums and effectiveness adjustments should be published by the CPUC.
4	Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process;	Should the mechanism allow LSEs to: **- Bid and show** **- Bid or show** **- PG&E's proposal (if an LSE voluntarily shows, the LSE cannot select the option to both bid and voluntarily show the resource as part of the CPE's solicitation process)** **- Other**	N/A
5	How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.	Should the premium be: **- Fixed for the term of the commitment** **- Adjusted year to year** **- Other**	Any premium should be fixed for the term of the commitment. Otherwise, it would create revenue uncertainty and discourage development of the desired resources.
6	How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?	In the Workshop, parties agreed that this should be addressed in a working group or through future proposals made in the RA proceeding, as suggested by the Commission (page 53-54 of D.20-02-006)	This issue should be addressed as expeditiously as possible. An initial, simple approach could be to use a multiplier to ensure that preferred resources receive extra value in the bid stack of CPE solicitations.
7	In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.	What should be the **cut off date** for legacy treatment of existing contracts?	N/A
		What are the **terms (length of time)** for applying legacy treatment of existing contracts?	N/A
		What should be the **eligibility rules** for the treatment of existing contracts?	N/A
8		**Other**	
9		**Overall**	

Summary of Parties' Informal Comments, submitted July 20, 2020		
Alliance for Retail Energy Market (AReM)	**California Community Choice Association (CalCCA)**	**California Energy Storage Alliance (CESA)**
N/A	Incorporated not through a price reduction, but into a technology-specific modification of the megawatt (MW); California Independent System Operator (CAISO) should lead a stakeholder process to develop factors that could be used.	Favors an approach where the central procurement entity (CPE) request for offer (RFO) considers identifying multiple portfolios of bid and shown resources that, on one end, considers effectiveness as the binding, initial screening criteria and, on the other end, more heavily considers preferred attributes while ensuring effectiveness.
N/A	Price premiums would be differentiated by local areas, including the disaggregated "PG&E Other" areas, unless a higher level of aggregation were required to mask the price of individual resource prices.	Generally supports granularity of the LCR reduction compensation mechanism and proposed the following premiums for consideration (1) closer-to-load, (2) Disadvantaged communities (DAC), (3) Greenhouse gas (GHG) emissions reduction and (4) market power mitigation; A one-size-fits-all premium may undercut the incremental value-add of certain projects.
N/A	N/A	One way to balance transparency with the need for confidentiality would be to consider base class-specific premiums that are broadly applicable to all resources within that class.
N/A	Load serving entity (LSE) must chose to either bid or show.	LSE may bid and/or show.
N/A	N/A	Year-to-year adjustment to the local compensation mechanism should not be established and may not be needed.
N/A	N/A	CPE RFO evaluation criteria mirror the premium factors in the local compensation mechanism, link to IRP-identified future long-term procurement needs in local or sub-local areas, adhere to the loading order and SB 1136.
Compensation mechanism adopted for preferred resources should be applied to existing contracts entered into by an LSE before June 11, 2020; not apply to fossil utility owned generation (UOG), which will be required to bid into the solicitation.	N/A	N/A
	Use of a median referent price, which is unaffected by high outliers in a price distribution. Recommends that resources be committed for a three-year term; Showing, like a successful bid, should be documented through a confirm.	
The ability for a LSE to receive a payment from the CPE must not result in over-procurement by the CPE with the over-procurement costs spread among all LSEs. The customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; they should not spread those costs to other LSEs or to the customers of other LSEs.		

California Efficiency + Demand Management Council (Council)
The CPUC should focus at least initially on a more simplistic approach, given the time contraints involved. Cost effectiveness of local resources should not be within the scope of the mechanism. Use limitations of resources should not be considered other than in the context of ensuring that MCC Bucket limitations are not violated. Local effectiveness of individual resources has not been defined by the CPUC and might be impractical for application to DR resources due to the sometimes dynamic nature of their customer and technology composition.
Factors on which to base a premium can be resource location, resource type (especially preferred resources), or operational characteristics or for resources located in DACs.
Should be as transparent as possible to ensure that resource providers can develop the products of greatest value. For similar reasons, each CPE's least-cost, best-fit methodology should be made as transparent as possible.
N/A
N/A
Both qualitative and quantitative criteria should be considered; pursuant to D.19-06-002, preferred resources should be favored over fossil-fuel resources and not disadvantaged, fairly compared to existing, fully-depreciated gas resources on a cost basis; greater consideration to low- or zero-emission resources in meeting State's environmental goals.
N/A

Pacific Gas and Electric Company (PG&E)	Public Advocates Office (CalPA)	Southern California Edison Company (SCE)
Local resources are not equally “effective” in meeting local area reliability needs; Should only be compensated for resources that either have been demonstrated to meet up-front eligibility requirements or have an effectiveness adjustment applied to the net qualifying capacity (NQC).	The effectiveness and ability of a resource to provide those local resource adequacy (RA) attributes should match or exceed the requirements of the Commission and/or CAISO that qualify specific technologies’ ability to count as local RA.	Local effectiveness is determined by CAISO based on the fleet of resources available and the contingencies that the fleet meets; CAISO would need to provide the information on effectiveness factors and the value of use-limited resources in meeting a local area need in its LCR studies.
Ideally, the proposed compensation mechanism would be calculated for each sub-local area; Should reflect the contribution of a resource type to local area reliability.	There should be pre-determined premiums calculated for each resource technology type.	The premium should reflect the actual contribution to the local RA need of a resource and market conditions; The level of granularity should consider, and very likely depend on, data availability and the robustness of the data that report historic RA prices for these areas.
Potential options include publishing aggregated data upfront and more granular data after a sufficient period of time has passed or publishing rankings (e.g., highest value area to lowest) or tiers with ranges (e.g., top five local premiums include these areas and are between \$5 and \$7).	The Commission should post the premium and include them in both its annual RA Report and the annual Final RA Guide; This may not be feasible if a premium is created for each unique resource since it may be calculated depending on market sensitive resource information.	The transparency of the premiums would depend heavily on the data used to determine the premiums.
LSE may 1) voluntarily show a resource for local premium but may not bid or 2) bid and voluntarily show the resource for no local premium.	N/A	Due to complexity, recommends this be discussed in workshops evaluating gaming risk.
Any effectiveness adjustment to local premiums should reflect the assumptions and findings of the most recent CAISO Local Capacity Technical Study Report.	Premium would increase or decrease as NQC is adjusted year to year.	Depends on details of the mechanism on how the effectiveness of resources is considered in deriving a premium.
N/A	N/A	Recommends to be addressed in the area of CPE implementation as it relates to the bid selection process and criteria.
Legacy treatment of LSE's local RA existing contracts should be applied only to contracts executed, or owned resources that were acquired, prior to issuance of D.19-02-022(3/4/2019); not to local resources procured outside of the LSE's transmission area charge (TAC) area; do not support being applied for the full term of an existing	N/A	Apply to only those existing resources signed before the issuance of central procurement decision on 3/26/2020; for new resources it could apply to contracts signed prior to the PD, therefore limitation is only for local RA contracts with existing resources - up to a five-year term length.

San Diego Gas & Electric Company (SDG&E)
Should be guided by the CAISO and the annual Local Capacity Technical Study.
Believes the complexity of developing individual premiums for the various types of resources in either sub-areas or local areas makes this task infeasible
N/A
N/A
N/A
N/A
Do not propose a separate rule for existing contracts, but not opposed to a one-time election exceeding the rolling three-year Local RA program.
Shown local RA capacity is committed for a period of up to three years; No process to decommit a resource except for certain reasons, such as resource retirements or force majeure.

Subject:	PG&E's Informal Comments for the Working Group on LCR RCM and Compensation Mechanism
Date:	Monday, August 3, 2020 at 5:10:46 PM Pacific Daylight Time
From:	Wan, Lisa
To:	Evelyn Kahl, 'ccsong@cleanpoweralliance.com', demerson@sonomacleanpower.org, mbrandt@ebce.org, Brown, Erica, Kikuyama, Rhett, Formosa, Noelle (Law), Shagun Tougas
Attachments:	Informal_Comments_LCR-CM_Workshop_20200803.pdf

All,

Attached please find PG&E's informal comments to the Working Group on LCR RCM and Compensation Mechanism.

Thank you,

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Informal Comments of Pacific Gas and Electric Company on the Working Group Workshop on the Local Capacity Requirement Reduction Compensation Mechanism and Treatment of Existing Contracts - Due August 3, 2020

Pacific Gas and Electric Company ("PG&E") provides the following informal comments on the working group workshop on the local capacity requirement reduction compensation mechanism ("LCR-RCM") and treatment of existing contracts, held on July 27, 2020 (the "Workshop") and co-led by PG&E and the California Community Choice Association ("CalCCA") (together, the "Co-Leads").

I. INTRODUCTION

At the Workshop, the Co-Leads presented materials summarizing parties' informal comments on items to be addressed by the working group as ordered in Decision ("D.") 20-06-002 (the "CPE Decision") on pages 43-45 and in Ordering Paragraphs 5 and 6. The Workshop also included presentations by PG&E, CalCCA and San Diego Gas & Electric Company ("SDG&E") on recommendations and/or proposals for consideration by the working group. In these informal comments on the Workshop, PG&E focuses on the following items that were discussed during the Workshop:

- How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources;
- How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas); and
- Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both mechanisms into

the bid evaluation process.

In reviewing the proposals put forward thus far, PG&E believes that none of them clearly meets all the objectives of the LCR-RCM set forth in D.20-06-002, but that two may be workable: (1) CalCCA's proposal to develop a premium price based on the median price of central procurement entity ("CPE") procured resources and apply an effectiveness adjustment based on each technology's contribution to local resource adequacy ("RA") requirements consistent with the California Independent System Operator Corporation's ("CAISO") Local Capacity Technical Study ("LCTS") and (2) CalCCA's proposal to allow voluntarily shown resources to "bid in" local RA attributes only.

II. CORE PRINCIPLES AND/OR OBJECTIVES FOR THE LCR-RCM

As the working group continues to develop a workable solution on the LCR-RCM and treatment of existing contracts, PG&E requests that the following principles, which are based on the California Public Utilities Commission's ("Commission") directives within the CPE Decision, guide the development of a proposal and the working group discussions, namely that the LCR-RCM should:

1. Incent preferred resource development in local areas:[1] The motivating factor behind establishing a working group to look at the LCR-RCM issue.
2. Reflect resource effectiveness at meeting reliability requirements to prevent "leaning" by LSEs:[2] Every load serving entity ("LSE") should equitably share the responsibility of ensuring local area reliability.
3. Provide ratepayer value by lowering total costs to customers without sacrificing

[1] CPE Decision, p. 41 ("…we recognize that a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas.").
[2] CPE Decision, p. 42 ("The Commission recognizes that a financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value would more closely align the financial compensation with the actual LCR MW reduction the resource provided.").

local area reliability:[3] Ratepayers should benefit from any mechanism through lower overall costs.

4. Avoid market power and/or gaming opportunities but may rather reflect a "premium" based on the additional cost of developing resources in local areas:[4] Avoiding market power and gaming is important to ensure the integrity of the RA program.

CalCCA and SDG&E outlined principles in developing proposals for an LCR-RCM and PG&E finds alignment among these parties with some of the core principles described above and provides the following table as a helpful matrix for assessing the proposals presented and how each scores against these principles. One exception is "provide ratepayer value," which CalCCA characterized as an objective of the resource's effectiveness process, but which PG&E believes is clearly outlined as a stand-alone principle in the CPE Decision.[5]

Some stakeholders touched on these principles in informal comments. For instance, the Alliance for Retail Energy Markets ("AReM") argued that "customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; they should not spread those costs to other LSEs or to the customers of other LSEs."[6] This aligns with the "provide ratepayer value" principle.

As mentioned above, PG&E provides the following table as a helpful matrix for assessing the proposals put forward thus far and how each scores against these principles.

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[3] CPE Decision, p. 42 ("Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSEs seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE in addressing LCR needs."), p. 43 ("…ratepayers are: (1) only compensating resources to the extent they provide ratepayer value.").
[4] CPE Decision, p. 42 ("A key purpose in creating a CPE framework is to reduce costs to ratepayers by mitigating local market power." And, p. 43: ratepayers are "only compensating LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs.").
[5] See p. 7 of CalCCA's workshop slides, which summarizes principles CalCCA gleaned from D.20-06-002.
[6] AReM Informal Comments, p. 2.

Matrix of Proposals and Principles

		Proposals		
Principles	**Decision Reference**	**CalCCA #1 (Provides a Guaranteed Incentive)**	**CalCCA #2 (Provides No Guarantee)**	**SDG&E**
Incent preferred resource development in local areas	p. 41	Unclear, provides guaranteed payment for shown resources in local areas.	Unclear, provides a mechanism for shown resources to receive payment for the local attribute but does not provide any certainty.	Unclear, needs testing.
Reflect resource effectiveness	p. 42	Yes, scales shown resource to average effectiveness factor.	Yes, CPE applies same criteria, including effectiveness, for both shown and bid resources.	No, applies a shown capacity to CPE-procured capacity ratio.
Provide ratepayer value Evaluated alongside bid resources	p. 42-43	Unclear, uses pre-determined value that may be higher or lower than bid resources.	Yes, shown resources are considered alongside bid resources; CPE may reject shown or bid resources if they do not provide value.	Unclear, uses pre-determined value that may be higher or lower than bid resources.
Avoid market power and gaming Pre-determined	p. 42-43; O¶ 5.b.	Unclear, would need to ensure that any inflated data is not included in pre-determined price.	Potentially, but unclear what role pre-determined price has.	Unclear, only avenue to mitigate market power is for the CPE to not procure.

III. COMMENTS ON AN EFFECTIVENESS ADJUSTMENT

In the Workshop, SDG&E proposed an effectiveness adjustment methodology using the percentage resulting from the local capacity area or sub-local area RA requirements divided by the total amount of voluntarily shown capacity and CPE-procured capacity. For example, if the RA requirements for a local capacity area is 60 megawatts (“MW”) and 30 MWs were voluntarily shown by LSEs, and 50 MWs were procured by the CPE, the percentage would be 75 percent, or 60 MWs / 80 MWs. This results in LSEs being compensated for 22.5 MWs of the 30

MWs that were voluntarily shown. PG&E has concerns with this approach and does not believe this methodology appropriately addresses cost effectiveness concerns, including evaluating local effectiveness and use-limitations of a voluntarily shown resource's contribution to local area reliability. In the example above, the CPE procured 50 MWs in addition to the 30 MWs of voluntarily shown resources to meet a local RA requirement of 60 MWs. Arguably, only 10 MWs of the voluntarily shown resources could be deemed as "effective" capacity; however, under SDG&E's proposal, 22.5 MWs would be compensated at the local RA premium, resulting in customers paying for 12.5 MWs of voluntarily shown resources that may not have provided any ratepayer value or any local area reliability benefits to the system. PG&E believes this methodology is overly simplified, does not reflect a resource's "effective" capacity, does not account for a resource's energy limitations, and does not prevent leaning by LSEs.

PG&E supports additional examination by the working group to assess other methods to value a resource's contribution to local area reliability, including CalCCA's proposal to use the CAISO's LCTS to look at the contribution of different resource types. CalCCA's proposal to use a calculated average of the CAISO's effectiveness factors, however, does not address how the effectiveness factors may only be used when comparing reliability needs of a single contingency. PG&E agrees with parties that developing effectiveness adjustments solely using CAISO's effectiveness factors is highly complex and potentially infeasible.[7] Under CalCCA's proposal, the CPE would determine the average percentage of the CAISO's effectiveness factors for CPE-procured resources and apply the average percentage to the MW amount of an LSE's voluntarily shown resource.[8] This MW-adjusted amount would be eligible for compensation at the local premium as part of the LCR-RCM.

As PG&E noted above, CAISO's effectiveness factors from Attachment B of the CAISO's LCTS are reflective of the single most binding/limiting constraint in a sub-local area.

[7] Southern California Edison Company Informal Comments, pp. 2-3; SDG&E Informal Comments, p. 2; CalCCA Informal Comments, p. 3.
[8] CalCCA's proposal is to use the CAISO's effectiveness factors as defined in Attachment B of the CAISO's LCTS and CAISO's Operating Procedure 2210Z.

However, sub-local areas have numerous constraints and a resource's effectiveness factor can vary by each constraint. Further, these factors could result in negative or positive impacts (e.g. a resource can be "ineffective" at relieving the loading on a constraint and can make it worse), and it is not clear how this will be considered in developing the average percentage amount or whether all constraints will be used. Given that CAISO's effectiveness factors of a resource depend on the evaluation of the portfolio as a whole, PG&E believes that even as an effectiveness proxy, the sole use of CAISO's effectiveness factors would not be a workable solution.

PG&E is considering whether other ways of assessing resource effectiveness may be further explored by the working group, as CAISO's effectiveness factors are only one component that should be considered when evaluating a resource's contribution to local area reliability.

IV. COMMENTS ON A PRICING METHODOLOGY

In the Workshop, SDG&E proposed that the local premium price be the difference between the weighted average price of the CPE-procured resources and the NP-15 or SP-15 market price benchmark for RA. PG&E notes that this methodology is similar to the financial crediting mechanism proposed by CalCCA in Rulemaking 17-09-020, which was rejected by the Commission. The CPE Decision stated: "[R]ather than the ex post benchmark proposed by CalCCA, the CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources." As a result, it is unclear how this differs from the mechanism that the Commission has already contemplated and rejected.

PG&E is also concerned that SDG&E's proposal lacks an effective measure to mitigate market power concerns and could introduce gaming opportunities. For example, LSEs could bid at high prices for "effective" capacity and show cheaper, less "effective" capacity. Shown resources would then be paid more than their marginal costs. Additionally, if a high volume of resources is shown in a given local area, other resources in that local area may adjust their price based on the local premium so that the local premium becomes a floor for otherwise cheaper resources.

Alternatively, CalCCA proposed to use the median price as opposed to an average or weighted average price for determining the local premium price. PG&E appreciates CalCCA's proposal and is interested to further understand CalCCA's proposal that a CPE identify and eliminate prices that reflect market power and exclude those prices from the calculation. For example, would the CPE assess the individual bid based on its understanding of unit costs and revenue streams or would the CPE simply identify pivotal supplier units for sub-areas and exclude those bids?

V. COMMENTS ON CALCCA'S PROPOSAL (OPTION #2)

PG&E appreciates CalCCA's efforts in putting forth a new proposal (referred to as Option #2) for the LCR-RCM and understands the proposal presented at the Workshop to have the following key elements:

- LSEs will be required to bid only the local RA attribute into the solicitation to receive compensation as part of the LCR-RCM;
- All resources will be evaluated simultaneously or alongside each other (e.g. as part of the entire pool of resources to be procured by the CPE); and
- The CPE may accept or reject shown resources at the price and quantity shown depending on the value relative to bid resources (e.g. there is no guaranteed premium for the LSE).

While PG&E does not find CalCCA's proposal (Option #2) to clearly meet all of the objectives in the CPE Decision, PG&E believes that the proposal is potentially a workable solution. Should parties be inclined to further develop CalCCA's proposal (Option #2), PG&E recommends that parties: (1) evaluate how the "unbundling" of RA attributes would work or impact other parts of the RA program, (2) determine any downstream impacts with CAISO if the Commission determines to "unbundle" RA for the LCR-RCM or in a future RA proceeding, and

(3) determine how to avoid double-counting of RA capacity or whether different counting rules may need to be established for system RA or local RA attributes. In addition, PG&E requests that CalCCA clarify whether its proposal (Option #2) would eliminate the "voluntarily shown" option from the CPE Decision and replace it with a "bid-in" option and, thus, effectively remove the voluntarily shown option from the CPE solicitation and evaluation process.

That said, PG&E appreciates CalCCA's efforts in putting forth a potentially workable solution and will continue to engage in the working group process to ensure the Commission's objectives as outlined in the CPE Decision are met.

VI. CONCLUSION

PG&E respectfully requests that these informal comments inform the Commission's consideration of the LCR-RCM.

Subject: R.17-09-020 and R.19-11-009_RA OIR: SCE Informal Comments Regarding Working Group Workshop on LCR Reduction Compensation Mechanism and Existing Contracts August 3, 2020

Date: Monday, August 3, 2020 at 3:55:45 PM Pacific Daylight Time

From: Legal.Admin@sce.com

To: S.Tougas@CleanEnergyregResearch.com

Attachments: R1709020-SCE Informal Comments on Working Group Workshop on LCR Reduction Compensation Mechanism and Existing Contracts 8-3-20.pdf, R1709020_Service List.pdf, R1911009_Service List.pdf

To all parties in R.17-09-020 and R.19-11-009:

Attached is Southern California Edison Company's Informal Comments Regarding Working Group Workshop on Local Capacity Requirement (LCR) Reduction Compensation Mechanism and Existing Contracts August 3, 2020. This document is hereby served by electronic mail upon all parties listed in the official service lists for R.17-09-020 and R.19-11-009.

(See attached file: R1709020-SCE Informal Comments on Working Group Workshop on LCR Reduction Compensation Mechanism and Existing Contracts 8-3-20.pdf)

(See attached file: R1709020_Service List.pdf)

(See attached file: R1911009_Service List.pdf)

Regards,

Legal Administration
Southern California Edison Company
Telephone: (626) 302-6950
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Southern California Edison Company's Informal Comments Regarding Working Group Workshop on Local Capacity Requirement (LCR) Reduction Compensation Mechanism and Existing Contracts
August 3, 2020

Southern California Edison Company (SCE) appreciates the opportunity to submit informal comments on the July 27, 2020 working group workshop regarding the LCR reduction compensation mechanism and treatment of existing resource adequacy (RA) contracts.
SCE thanks the co-leads for facilitating the workshop and parties for presenting their proposals. SCE also thanks all parties for their engagement and constructive discussion during the workshop.

A. Comments on California Community Choice Association (CalCCA) Proposals

CalCCA proposed two options for establishing a LCR reduction compensation mechanism: CalCCA Proposal #1 and CalCCA Proposal #2.[1] SCE understands that under CalCCA Proposal #1, a shown resource will be treated as "must take" by the central procurement entity (CPE) and will be paid at a pre-determined price (i.e., the local RA premium) for its effective net qualifying capacity (NQC). The effective NQC will be calculated based on the NQC of the resource and its relative effectiveness factor, i.e., the resource effectiveness factor compared to the average effectiveness factor of CPE-procured resources. Under CalCCA Proposal #2, a shown resource will "bid" its local attribute to the CPE at a price up to the pre-determined local RA premium and its bid will be considered alongside bids in the CPE solicitation. For both proposals, the pre-determined price is calculated as the difference between the Energy Division Power Charge Indifference Adjustment (PCIA) price for system RA and the Energy Division PCIA price for local RA in Year 1 or the most recent reported CPE local RA price for subsequent years. The calculation can use the median price or an average price after removing market-power-inflated prices. CalCCA proposes to use the last two quarters of the price information to derive the pre-determined price.

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1 CalCCA July 27 Workshop Presentation at 10-13.

The proposal to use only the last two quarters' information does not result in adequate price samples. The Energy Division annual RA report contains information for the entire year. The price information for the entire year should be used to calculate the premium.

SCE believes that both CalCCA Proposal #1 and CalCCA Proposal #2, presented during the workshop, have merits that should be further explored. Further exploration is needed to develop the details and address questions and potential issues with both proposals and allow for possible consensus among the parties. To this end, SCE thanks the co-leads for the updated schedule providing an additional opportunity to comment on the CalCCA proposals and any other potential proposals, and looks forward to better understanding the proposals and providing its comments throughout the remainder of the working group process.

B. Comments on Other Proposals and Issues

Several parties propose that a load-serving entity (LSE) should be allowed to bid or show, but not both.[2] As commented previously, SCE agrees that the potential for gaming bids based upon known minimum premium values and the resultant efficiency of the procurement process must be examined.[3] Allowing LSEs to both bid and show will likely raise the potential for gaming. At this point, SCE finds the proposal "to bid or show, but not both" generally reasonable. In particular, SCE understands that, under this proposal, an LSE could bid a local resource, or could show the resource and get paid through the pre-determined premium when applicable; however, the LSE will not be allowed to bid the resource with a flag to indicate that it will show the resource and get paid through the pre-determined premium if the resource is not selected by the CPE.

As commented by several parties, SCE continues to find it is reasonable to have a cut-off date for existing contracts to be eligible for a local RA compensation premium, if applicable, and the cut-off date should be around the date when the Proposed Decision or the Final Decision was

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[2] CalCCA July 27 Workshop Presentation at 14; Pacific Gas and Electric Company (PG&E) Informal Comments at 4.

[3] SCE Informal Comments at 4.

issued, i.e., either March 26, 2020 or June 11, 2020. SCE is not opposed to PG&E's proposal that the cut-off date should be the date of issuance of D.19-02-022, i.e., March 4, 2019.[4] Further, the payment of an LCR reduction compensation mechanism for existing resources, if applicable, should be for up to a five-year term length.

C. Conclusion

SCE looks forward to further discussion and parties' consideration on the issues outlined above and other related issues.

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[4] PG&E Informal Comments at 5.

Subject: FW: [RA - LCR RCM Working Group] Matrix and Presentations
Date: Monday, August 3, 2020 at 5:01:12 PM Pacific Daylight Time
From: Wan, Lisa
To: Shagun Tougas, Evelyn Kahl
CC: Formosa, Noelle (Law)
Attachments: MATRIX_CPE-LCR-RCM_Party-Positions +SDG&E.xlsx

FYI

From: Chase, Tina <CChase@sdge.com>
Sent: Monday, August 03, 2020 10:07 AM
To: Wan, Lisa <L2WG@pge.com>; evelyn@cal-cca.org; CC Song <csong@cleanpoweralliance.org>; Deb Emerson <demerson@sonomacleanpower.org>; mbrandt@ebce.org; Brown, Erica <e1ba@pge.com>; Kikuyama, Rhett <R2K3@pge.com>; Formosa, Noelle (Law) <NRF6@pge.com>
Subject: RE: [RA - LCR RCM Working Group] Matrix and Presentations

*******CAUTION: This email was sent from an EXTERNAL source. Think before clicking links or opening attachments.*******
Hi all, attached please find the matrix with the updated SDG&E column. Thanks -Tina

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From: Wan, Lisa <L2WG@pge.com>
Sent: Thursday, July 30, 2020 3:14 PM
To: Evelyn Kahl <evelyn@cal-cca.org>; 'ccsong@cleanpoweralliance.com' <ccsong@cleanpoweralliance.com>; demerson@sonomacleanpower.org; mbrandt@ebce.org; Brown, Erica <e1ba@pge.com>; Kikuyama, Rhett <R2K3@pge.com>; Wan, Lisa <L2WG@pge.com>; Formosa, Noelle (Law) <NRF6@pge.com>
Cc: Nickerman, Luke <LxNg@pge.com>; erdal.kara@vistraenergy.com; csanada@caiso.com; Rybka, Greg <GMRA@pge.com>; skeehn@mbcp.org; patrick.cunningham@cpuc.ca.gov; samk@pioneercommunityenergy.ca.gov; william.rostov@sfcityatty.org; ckeys@peninsulacleanenergy.com; jennifer.chamberlin@cpowerenergymanagement.com; john.leslie@dentons.com; rachel.mcmahon@sunrun.com; david.vidaver@energy.ca.gov; linnan.cao@cpuc.ca.gov; jose.torrebueno@cc-energy.org; peter.mcferrin@sce.com; Miller, Ryan - Mktg Affil-E&FP <RMiller3@sdge.com>; jonathan.lakey@cpuc.ca.gov; brian@pacificea.com; christine.powell@cpuc.ca.gov; cathy.karlstad@sce.com; agregory@pilotpowergroup.com; Ashley Lewis Bernstein <Ashley.Bernstein@calpine.com>; Smith, Aimee <AMSmith@sdge.com>; cgrinstead@cleanpoweralliance.org; msusko@ebce.org; barmackm@calpine.com; Tang, Nuo - Mktg Affil-E&FP <NTang@sdge.com>; jabari.martin@sce.com; btheaker@mrpgenco.com; mary.lynch@constellation.com; amaani@leap.ac; wei.zhou@sce.com; jnoh@storagealliance.org; l.tougas@cleanenergyregresearch.com; beth@cal-cca.org; Soe, Alan Z <ASoe@sdge.com>; steve.greenleaf@brookfieldrenewable.com; philm@scdenergy.com; amorris@storagealliance.org; michael.evans@shell.com; Gao, Helen Z <HGao@sdge.com>; bsb@eslawfirm.com; sue.mara@rtoadvisors.com; Chase, Tina <CChase@sdge.com>; sduenas@storagealliance.org; jaimerose.gannon@cpuc.ca.gov; tyson@protectourcommunities.org; tbrunello@calstrat.com; Garcia-Rodriguez, Lizzette <LGarcia-Rodriguez@sdge.com>; klatt@energyattorney.com; mark.hesters@energy.ca.gov; carleigh@ceert.org; cbriggs@eslawfirm.com; acissna@redwoodenergy.org; ad1@cpuc.ca.gov; malcolm.ainspan@nrg.com; gcontreras@wellhead.com; kyle.navis@cpuc.ca.gov; Griffes, Peter <PHG3@pge.com>; ska@cpuc.ca.gov; Moussa, Effat A <EMoussa@sdge.com>; eric.little@sce.com; dougbocc@flynnrci.com
Subject: [EXTERNAL] [RA - LCR RCM Working Group] Matrix and Presentations

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All,

Attached, please find the presentations from the Monday 7/27 *Working Group Workshop on Local Capacity Requirement Reduction*
Compensation Mechanism and Treatment of Existing Contracts and the Matrix on Party Positions.

For the Matrix on Party Positions, please note the following:

- Please provide your organization's position or preferences for the issues laid out in the matrix. Please fill out the light orange column and note the name of your organization.
- Please send the matrix back to the co-leads on Monday 8/3. This is the same day as when the informal comments on the workshop to co-leads are due.
- For our reference, the co-leads have included a summary of the informal comments submitted Monday 7/20. If there are any misstatements, please make any necessary edits and let us know.
- If you'd like to provide a summary of your Monday 8/3 comments in the matrix, please feel free to do so.

If you have any questions, please feel free to reach out to me (lisa.wan@pge.com) or Shagun Tougas (s.tougas@cleanenergyregresearch.com).

Thank you,

Lisa Wan
PG&E | Regulatory Affairs
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Working Group on Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Treatment of Existing Contracts

		Matrix of Parties' Positions/Preferences	
No.	**Question**	**[Additional Question]**	**[NAME OF PARTY]**
1	How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?	Should effectiveness be determined by using the: **- CAISO's Effectiveness Factors** **- CAISO's LCTS Contribution to Peak Load Methodology** **- CAISO's LCTS Energy Storage Limitation Study** **- Other**	
2	How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);	Should effectiveness adjustments be applied to the: **- Price premium** **- MW of shown capacity** **- Other**	
		Should different **technology types** receive different premiums?	
		Should premiums be developed at the location level: **- TAC area only** **- Local area (e.g. Bay Area)** **- Sub local area (e.g. South Bay / Moss Landing)**	
3	How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;	Should the premiums be: - **Publicly posted** - **Confidential** - **Other**	
		To balance transparency and market sensitive information, how should the data be presented: **- Aggregated** - **Individual** - **Other**	
		Should the premiums or effectiveness adjustments be: - **Published by the Commission** - **Other**	
4	Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process;	Should the mechanism allow LSEs to: **- Bid and show** **- Bid or show** **- PG&E's proposal (if an LSE voluntarily shows, the LSE cannot select the option to both bid and voluntarily show the resource as part of the CPE's solicitation process)** **- Other**	
5	How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.	Should the premium be: - **Fixed for the term of the commitment** - **Adjusted year to year** - **Other**	
6	How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?	In the Workshop, parties agreed that this should be addressed in a working group or through future proposals made in the RA proceeding, as suggested by the Commission (page 53-54 of D.20-02-006)	
7	In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.	What should be the **cut off date** for legacy treatment of existing contracts?	
		What are the **terms (length of time)** for applying legacy treatment of existing contracts?	
		What should be the **eligibility rules** for the treatment of existing contracts?	
8		**Other**	
9		**Overall**	

Working Group on Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Treatment of Existing Contracts

Summary of Parties' Informal Comments, submitted July 20, 2020

Alliance for Retail Energy Market (AReM)	California Community Choice Association (CalCCA)	California Energy Storage Alliance (CESA)
N/A	Incorporated not through a price reduction, but into a technology-specific modification of the megawatt (MW); California Independent System Operator (CAISO) should lead a stakeholder process to develop factors that could be used.	Favors an approach where the central procurement entity (CPE) request for offer (RFO) considers identifying multiple portfolios of bid and shown resources that, on one end, considers effectiveness as the binding, initial screening criteria and, on the other end, more heavily considers preferred attributes while ensuring effectiveness.
N/A	Price premiums would be differentiated by local areas, including the disaggregated "PG&E Other" areas, unless a higher level of aggregation were required to mask the price of individual resource prices.	Generally supports granularity of the LCR reduction compensation mechanism and proposed the following premiums for consideration (1) closer-to-load, (2) Disadvantaged communities (DAC), (3) Greenhouse gas (GHG) emissions reduction and (4) market power mitigation; A one-size-fits-all premium may undercut the incremental value-add of certain projects.
N/A	N/A	One way to balance transparency with the need for confidentiality would be to consider base class-specific premiums that are broadly applicable to all resources within that class.
N/A	Load serving entity (LSE) must chose to either bid or show.	LSE may bid and/or show.
N/A	N/A	Year-to-year adjustment to the local compensation mechanism should not be established and may not be needed.
N/A	N/A	CPE RFO evaluation criteria mirror the premium factors in the local compensation mechanism, link to IRP-identified future long-term procurement needs in local or sub-local areas, adhere to the loading order and SB 1136.
Compensation mechanism adopted for preferred resources should be applied to existing contracts entered into by an LSE before June 11, 2020; not apply to fossil utility owned generation (UOG), which will be required to bid into the solicitation.	N/A	N/A
	Use of a median referent price, which is unaffected by high outliers in a price distribution. Recommends that resources be committed for a three-year term; Showing, like a successful bid, should be documented through a confirm.	
The ability for a LSE to receive a payment from the CPE must not result in over-procurement by the CPE with the over-procurement costs spread among all LSEs. The customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; they should not spread those costs to other LSEs or to the customers of other LSEs.		

California Efficiency + Demand Management Council (Council)
Cost effectiveness of local resources should not be within the scope of the mechanism.
Factors on which to base a premium can be resource location, resource type (especially preferred resources), or operational characteristics or for resources located in DACs.
Should be as transparent as possible to ensure that resource providers can develop the products of greatest value.
N/A
N/A
Both qualitative and quantitative criteria should be considered; preferred resources - favored over fossil-fuel resources and not disadvantaged, fairly compared to existing, fully-depreciated gas resources on a cost basis; greater consideration to low- or zero-emission resources in meeting State's environmental goals.
N/A

Pacific Gas and Electric Company (PG&E)	Public Advocates Office (CalPA)	Southern California Edison Company (SCE)
Local resources are not equally “effective” in meeting local area reliability needs; Should only be compensated for resources that either have been demonstrated to meet up-front eligibility requirements or have an effectiveness adjustment applied to the net qualifying capacity (NQC).	The effectiveness and ability of a resource to provide those local resource adequacy (RA) attributes should match or exceed the requirements of the Commission and/or CAISO that qualify specific technologies’ ability to count as local RA.	Local effectiveness is determined by CAISO based on the fleet of resources available and the contingencies that the fleet meets; CAISO would need to provide the information on effectiveness factors and the value of use-limited resources in meeting a local area need in its LCR studies.
Ideally, the proposed compensation mechanism would be calculated for each sub-local area; Should reflect the contribution of a resource type to local area reliability.	There should be pre-determined premiums calculated for each resource technology type.	The premium should reflect the actual contribution to the local RA need of a resource and market conditions; The level of granularity should consider, and very likely depend on, data availability and the robustness of the data that report historic RA prices for these areas.
Potential options include publishing aggregated data upfront and more granular data after a sufficient period of time has passed or publishing rankings (e.g., highest value area to lowest) or tiers with ranges (e.g., top five local premiums include these areas and are between $5 and $7).	The Commission should post the premium and include them in both its annual RA Report and the annual Final RA Guide; This may not be feasible if a premium is created for each unique resource since it may be calculated depending on market sensitive resource information.	The transparency of the premiums would depend heavily on the data used to determine the premiums.
LSE may 1) voluntarily show a resource for local premium but may not bid or 2) bid and voluntarily show the resource for no local premium.	N/A	Due to complexity, recommends this be discussed in workshops evaluating gaming risk.
Any effectiveness adjustment to local premiums should reflect the assumptions and findings of the most recent CAISO Local Capacity Technical Study Report.	Premium would increase or decrease as NQC is adjusted year to year.	Depends on details of the mechanism on how the effectiveness of resources is considered in deriving a premium.
N/A	N/A	Recommends to be addressed in the area of CPE implementation as it relates to the bid selection process and criteria.
Legacy treatment of LSE's local RA existing contracts should be applied only to contracts executed, or owned resources that were acquired, prior to issuance of D.19-02-022(3/4/2019); not to local resources procured outside of the LSE's transmission area charge (TAC) area; do not support being applied for the full term of an existing	N/A	Apply to only those existing resources signed before the issuance of central procurement decision on 3/26/2020; for new resources it could apply to contracts signed prior to the PD, therefore limitation is only for local RA contracts with existing resources - up to a five-year term length.

San Diego Gas & Electric Company (SDG&E)
Should be guided by the CAISO and the annual Local Capacity Technical Study. However, SDG&E offers a simpler solution based on total CPE procured MWs and Shown relative to the LCR.
Proposes single premium for all resource types. Premium can be local area specific or broken down into sub-areas if sufficient data is available. Believes the complexity of developing individual premiums for the various types of resources in either sub-areas or local areas makes this task infeasible.
Utilize CPE procured costs compared to PCIA System Market Priced Benchmarks.
Compensation Mechanism is only applicable for resources that either Show or Bid and Show if not selected.
Compensation Mechanism adjusts annually based on the capacity that CPE procured and Shown, the updated LCR, the CPE procurement costs and the PCIA System RA MPB
N/A
Do not propose a separate rule for existing contracts, but not opposed to a one-time election exceeding the rolling three-year Local RA program.
Provided additional details of the commitments for Shown resources as years roll forward. Shown local RA capacity is committed for a period of up to three years; No process to decommit a resource except for certain reasons, such as resource retirements or force majeure.
SDG&E believes its proposal offers a simple approach to meeting the needs of creating a Local Capacity Reduction Compensation Mechanism using transparent and annually refreshed data. SDG&E believes that while a more granular methodology may provide additional precision or "value" to specific resource types and various areas, the potential lack of available data may cause such a methodology to be difficult to implement.

Subject: R.17-09-020 and R.19-11-009 RA OIR: Wellhead Informal Comments on LCR Reduction Mechanism workshop

Date: Monday, August 3, 2020 at 5:02:39 PM Pacific Daylight Time

From: Greg Contreras

To: mm2@cpuc.ca.gov, Diamond@EnergyHub.net, KIrvin@Sidley.com, BBlair@ThompsonCoburn.com, Amanda.Frazier@VistraEnergy.com, DGetts@SouthWesternPower.com, shenricksen@ORMAT.COM, P.Shepard@dgc-us.com, Klatt@EnergyAttorney.com, Cathy.Karlstad@sce.com, Ty@TosdalAPC.com, John.Leslie@Dentons.com, AMSmith@SempraUtilities.com, MMcDaniels@CPV.com, ryan.baron@bbklaw.com, ryan.baron@bbklaw.com, ryan.baron@bbklaw.com, Mona.Tierney-Lloyd@Enel.com, JWiedman@PeninsulaCleanEnergy.com, Sue.Mara@RTOadvisors.com, Hilary.Staver@SVCleanEnergy.org, Suzy.Hong@SFcityAtty.org, TLong@turn.org, JKantor@KeyesFox.com, Colin.Meehan@FirstSolar.com, MAlcantar@Buchalter.com, NRF6@pge.com, NSheriff@Buchalter.com, John@OhmConnect.com, NicholasC@AdvMicrogrid.com, BCragg@GoodinMacBride.com, JArmstrong@GoodinMacBride.com, MVespa@Earthjustice.org, VidhyaPrabhakaran@dwt.com, PatrickFerguson@dwt.com, SSMyers@att.net, Debra.Lloyd@CityofPaloAlto.org, SArora@LSpower.com, JWeinstein@JWeinsteinLaw.com, 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Attachments: Service List R.19-11-009.pdf, Service List R.17-09-020.pdf, R.19-09-020 and R.19-11-009-Wellhead-informal Comments on LCR Reduction Mechanism.pdf

Dear Parties to R.17-09-020 and R.19-11-009,

Attached are Wellhead's informal comments on the LCR Reduction Mechanism Workshop.

Gregory Contreras
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Wellhead Electric Company, Inc.'s informal comments regarding the LCR Reduction Compensation Mechanism Workshop on 7/27/20.

Wellhead Electric Company, Inc. ("Wellhead") appreciates the opportunity to submit these informal comments on LCR reduction compensation Mechanism (the "Mechanism") workshop held July 27, 2020.

Wellhead would like to take this opportunity to seek support from parties to clarify that the Commission's exclusion of fossil fuel resources from the Mechanism was specifically for fossil fuel only resources and not hybridized resources including gas-storage resources ("Hybrids").

The working group should request clarification from the Commission stating that hybridized gas-storage resources are eligible for the Mechanism. The Decision states that "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas"[1]. As directed by Public Utilities Code 380[2], the Commission should use the Mechanism to incentivize the hybridization of existing gas resources. Many parties may already assume that Hybrids are eligible, but nonetheless to avoid confusion an express statement to that effect should be made

As discussed in prior comments in the IRP proceeding, hybridizing a sub-set of the gas-fired fleet is optimal because, amongst other things, it results in the following:

1. An immediate reduction in an GHG emissions.
2. An immediate reduction in the number of unit starts leading to lower NOx emissions in Disadvantaged Communities.

Hybridization furthers the State's clean energy goals while ensuring a high level of reliability. For this reason, and to comply with Public Utilities Code 380, Hybrids should be eligible for the Mechanism.

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[1] Decision on Central Procurement of the Resource Adequacy Program, dated 6/17/2020, pg. 41.

[2] Section 380(b)(1) of the PUC code states in pertinent part that the Commission should "Facilitate development of…hybrid capacity and retention of existing…hybrid capacity that is economic and needed."

Subject: [R.17-09-020 and R.19-11-009] Informal Comments on WG WS on LCR Compensation Mechanism and Treatment of Existing Contracts

Date: Tuesday, August 4, 2020 at 4:27:02 PM Pacific Daylight Time

From: Shawn-Dai Linderman

To: R2K3@pge.com, SCU1@pge.com, SREA@pge.com, sdri@pge.com, Ek-Info@Buchalter.com, FJackson.Stoddard@MorganLewis.com, monica.schwebs@morganlewis.com, lrafii@buchalter.com, L.Tougas@CleanEnergyregresearch.com, Maria@OhmConnect.com, NicholasC@AdvMicrogrid.com, Shagun Tougas, AnnaFero@dwt.com, TBrunello@Calstrat.com, Buck.Endemann@KLGates.com, jmcintyre@goodinmacbride.com, KatieJorrie@dwt.com, MSomogyi@GoodinMacBride.com, nsikand@goodinmacbride.com, Tara.Kaushik@HKlaw.com, DWTcpucDockets@dwt.com, Allie@Reimagine-Power.com, steven@moss.net, james@voltus.co, mplante@voltus.co, charles.middlekauff@pge.com, SSMyers@att.net, RegRelcpucCases@pge.com, Debra.Lloyd@CityofPaloAlto.org, fwahl@tesla.com

Attachments: AReM Informal Comments on LCR RCM Worskhop Email_8-3-2020.pdf, AReM Informal Comments on LCR RCM Worskhop Matrix_8-3-2020.xlsx, CalCCA Informal Comments on LCR RCM Worskhop Email_8-3-2020.pdf, CalCCA Informal Comments on LCR RCM Worskhop_8-3-2020.pdf, Calpine Informal Comments on LCR RCM Worskhop Matrix_8-3-2020.xlsx, Calpine Informal Comments on LCR RCM Worskhop_8-3-2020.pdf, Council Informal Comments on LCR RCM Worskhop Matrix_8-3-2020.xlsx, Council Informal Comments on LCR RCM Worskhop_8-3-2020.pdf, PG&E Informal Comments on LCR RCM Worskhop Email_8-3-2020.pdf, PG&E Informal Comments on LCR RCM Worskhop_8-3-2020.pdf, SCE Informal Comments on LCR RCM Worskhop Email_8-3-2020.pdf, SCE Informal Comments on LCR RCM Worskhop_8-3-2020.pdf, SDG&E Informal Comments on LCR RCM Worskhop Email_8-3-2020.pdf, SDG&E Informal Comments on LCR RCM Worskhop Matrix_8-3-2020.xlsx, Wellhead Informal

To R.17-09-020 and R.19-11-009 Service Lists:

Attached for your review are the informal comments the co-leads (CalCCA and PG&E) received on the July 27 Working Group Workshop on Local Capacity Requirement (LCR) Reduction Compensation Mechanism (RCM) and Treatment of Existing Contracts.

Informal reply comments on the workshop are due on August 17. Please send your reply comments to the co-leads listed below and the service lists.

Below is the updated upcoming schedule recently distributed for your convenience.

Event	Due Date
Parties Provide Informal Reply Comments on Workshop to Co-Leads	August 17, 2020
Co-Leads to email the draft Working Group Report to Working Group participants for review	August 19, 2020
Working Group participants to email their comments on the draft Working Group Report to the Co-Leads	August 26, 2020
Co-Leads File Working Group Report	September 1, 2020

Co-leads:

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Please contact Lisa Wan at lisa.wan@pge.com and Shagun Tougas at s.tougas@CleanEnergyRegResearch.com with any questions.

Thank you.

Shawn-Dai Linderman

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To keep up with CCA news subscribe to our mailing list here.
You can also follow CalCCA on Twitter and LinkedIn.

APPENDIX E

AUGUST 17, 2020 INFORMAL REPLY COMMENTS

Subject: AReM's Informal Reply Comments on LCR Reduction Compensation Mechanism
Date: Monday, August 17, 2020 at 3:43:53 PM Pacific Daylight Time
From: Sue Mara
To: Karl Meeusen, knv@cpuc.ca.gov, KPeniche@sdge.com, KPerez@caiso.com, L.Tougas@CleanEnergyregresearch.com, Wan, Lisa, Lauren.Miller@SFcityAtty.org, LCARR@caiso.com, Legal.Admin@sce.com, LFisher@PublicGeneratingPool.com, lfreeman@sidley.com, Liddell@EnergyAttorney.com, Lisa.Cherkas@MorganStanley.com, Liz.gill@energy.ca.gov, liz@CEERT.org, LJPN@pge.com, LMP@dwgp.com, LRafii@Buchalter.com, LT3@cpuc.ca.gov, LTrolese@PublicGeneratingPool.com, Luisa.Elkins@SanJoseCa.gov, LValero@anaheim.net, Nickerman, Luke, Marshall, Lynn@Energy, MAlcantar@Buchalter.com, Ainspan, Malcolm, Malinda@ProtectOurCommunities.org, Marc.Monbouquette@Enel.com, 'Marcie Milner, Margaret.Miller@Avangrid.com, Maria@OhmConnect.com, Mark Byron, marketdev@leap.energy, Martha.Helak@smud.org, matthew.everett@sce.com, MBrandt@ebce.org, MCade@Buchalter.com, mcollins@nexant.com, md9@cpuc.ca.gov, mdeen@ppcpdx.org, MeganMMyers@yahoo.com, Melicia.Charles@Sunrun.com, mf6@cpuc.ca.gov, Michael.Evans@shell.com, Miguel.Cerrutti@Energy.ca.gov, mike.benn@powerex.com, MikeMoore315@Yahoo.com, Michelle Kito, MKubow@mrpgenco.com, MLanger@CleanPowerAlliance.org, mm2@cpuc.ca.gov, mm5@cpuc.ca.gov, MMcDaniels@CPV.com, Chan, Maggie, MMcNaul@ThompsonCoburn.com, Wilson, Maria Vanko (Law), Mona Tierney-Lloyd, monica.schwebs@morganlewis.com, MPan@Anaheim.net, mplante@voltus.co, mpoage@caiso.com, MRP@dwgp.com, MRW@MRWassoc.com, ms9@cpuc.ca.gov, MSomogyi@GoodinMacBride.com, MSpecht@ucsusa.org, MThomas@Buchalter.com, Molly Sterkel, MVespa@Earthjustice.org, nbarba@frontierenergy.com, nburki@anaheim.net, nd2@cpuc.ca.gov, ng3@cpuc.ca.gov, NicholasC@AdvMicrogrid.com, NKeefer@CleanPowerAlliance.org, Nathaniel Malcolm, NMiksis@FlynnRCI.com, Noelani.Derrickson@FirstSolar.com, nquan@gswater.com, nr2@cpuc.ca.gov, NRader@Calwea.org, NReardon@SonomaCleanPower.org, Formosa, Noelle (Law), NSaracino@WEAWLaw.com, NShaughnessy@BGCpartners.com, Nora Sheriff, nsikand@goodinmacbride.com, Tang, Nuo - Mktg Affil-E&FP, NWhang@CleanPowerAlliance.org, P.Shepard@dgc-us.com, Cunningham, Patrick, PatrickFerguson@dwt.com, paul.douglas10@gmail.com, Paul@BarkovichAndYap.com, PCummins@Wellhead.com, David Peffer, Griffes, Peter, Phillip Muller, Policy@CEDMC.org, Poonum Agrawal, PPearson@MBCommunityPower.org, pthomsen@ormat.com, pushkarwagle@flynnrci.com, pva@cpuc.ca.gov, py2@cpuc.ca.gov, r1911009@olivineinc.com, Kikuyama, Rhett, Rachel.McMahon@SunRun.com, RBird@BorregoSolar.com, rc5@cpuc.ca.gov, RegAffairs@FormEnergy.com, RegRelCPUCCases@pge.com, Regulatory@BraunLegal.com, regulatory@cal-cca.org, Regulatory@ebce.org, Regulatory@mceCleanEnergy.org, Regulatory@PilotPowerGroup.com, RGerlach@BorregoSolar.com, RKing@GoodCompanyAssociates.com, RKoss@AdamsBroadwell.com, Ryan Kurlinski, RL@esLawFirm.com, rmccann@umich.edu, rmcferrin@weawlaw.com, Robin@ZGlobal.biz, Bakousseva, Renata, RSankaran@mmrgrp.com, rshelton@thompsoncoburn.com, ryan.baron@bbklaw.com, S.Tougas@CleanEnergyregResearch.com, Sam.Schabacker@BloomEnergy.com, Sarah.Qureshi@NextEraEnergy.com, Sarita_Sarvate@yahoo.com, SArora@LSpower.com, sb6@cpuc.ca.gov, sbarata@opiniondynamics.com, sberelson@cedmc.org, scs@cpuc.ca.gov, Uriza, Sarina, sdoherty@peninsulacleanenergy.com, Scott Ranzall, Sean.Beatty@nrg.com, sgn@eslawfirm.com, sgreenleaf@ces-ltd.com, Sharon.Yang@LibertyUtilities.com, shenricksen@ORMAT.com, skeehn@mbcp.org, SKozal@Buchalter.com, SLazerow@cbecal.org, SMN@dwgp.com, SPauker@KeyesFox.com, Ellis, Savi, Sara Myers,

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Attachments: AReM's Informal Reply -- LCR Reduction Compensation Mechanism.pdf

To Co-Leads of Working Group on LCR Reduction Compensation Mechanism and Treatment of Existing Contracts:

As requested in your e-mail of August 4, 2020, attached are the informal reply comments of the Alliance for Retail Energy Markets (AReM) regarding the Local Capacity Requirement (LCR) Reduction Compensation Mechanism.

These comments have also been sent to the service lists for R.17-09-020 and R.19-11-009, as you requested.

Because of the size of the combined service lists, these comments have been sent in two transmissions.

Please contact me with any questions.

Regards,

Sue Mara
On Behalf of AReM

cc: Service Lists for R.17-09-020 and R.19-11-009

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Committed to Preserving and Expanding Consumer Choice in California's Electricity Marketplace

Alliance for Retail Energy Markets

INFORMAL REPLY OF THE
ALLIANCE FOR RETAIL ENERGY MARKETS ON
LCR REDUCTION COMPENSATION MECHANISM
(R.19-11-009)

As requested by e-mail on August 4, 2020 by the Co-Leads of the Working Group directed in Ordering Paragraph 5 of Decision ("D.") 20-06-002 implementing the Central Procurement Entity ("CPE"), the Alliance for Retail Energy Markets ("AReM")[1] submits this informal reply to comments submitted August 3, 2020 regarding the Local Capacity Requirements ("LCR") Reduction Compensation Mechanism.

1. <u>Bids Outside Of The Auction Process</u>

Calpine states: [G]iven that the CPE would be able to compare shown and bid resources in the solicitation, it is unclear why it would be necessary to establish pre-specified premiums for shown resources." AReM concurs with Calpine that bids outside of the auction process should not be permitted.

AReM further concurs with Calpine's proposal to give load-serving entities ("LSEs") "full flexibility to specify the prices at which shown resources will be compared to bid resources" in the CPE's auction to provide LSEs "incentives to offer competitively to ensure that their resources are selected over offered resources." AReM recommends that the Co-Leads incorporate Calpine's recommendations into Straw Proposal #2.

[1] AReM is a California non-profit mutual benefit corporation formed by electric service providers that are active in the California's direct access market. This filing represents the position of AReM, but not necessarily that of a particular member or any affiliates of its members with respect to the issues addressed herein.

2. Use of Benchmarks

AReM is concerned that any backwards-looking benchmark is based on stale data with the "staleness" exacerbated by the length of the backward look. Thus, AReM opposes SCE's suggestion (page 2) to use an entire year of RA pricing as a benchmark.

In addition, AReM is concerned about the ability of any benchmark to provide an apples-to-apples comparison relative to CPE needs. If a single benchmark is used, it is unlikely to take into consideration different locations, contract terms, or temporal aspects. For example, third quarter RA is the most expensive. Thus, the CalCCA proposal, which would use third and fourth quarter data for a first quarter auction, would not be reflective of the price for that time period, even if it is only a premium calculation.

3. Risks of Market Power and Gaming

PG&E's matrix (page 4) demonstrates that all options for a compensation mechanism have risks for "market power and gaming." AReM has the same concerns. Accordingly, AReM questions if the limited potential benefits warrant moving forward with any compensation mechanism.

Submitted on behalf of AReM by:
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August 17, 2020

Shawn-Dai Linderman

From:	Shawn-Dai Linderman
Sent:	Monday, August 17, 2020 5:25 PM
To:	CalCCA Regulatory; DFranz@Tesla.com; GBrehm@lspower.com; JAC@CPowerEnergyManagement.com; Sean.Beatty@nrg.com; Policy@CEDMC.org; MSpecht@ucsusa.org; Mark.Byron@UCOP.edu; Melissa Brandt; CESA_Regulatory@StorageAlliance.org; GMorris@emf.net; NRader@Calwea.org; nmalcolm@mcecleanenergy.org; Yue-Han.Chow@SanJoseCa.gov; nreardon@sonomacleanpower.org; JPinjuv@caiso.com; Danielle@RenewableEnergyStrat.com; Dan@GoldenStateCleanEnergy.com; cmkehrein@ems-ca.com; PCummins@Wellhead.com; Peffer@BraunLegal.com; John@JMcKinseylaw.com; BSB@ESLawFirm.com; eddyconsulting@gmail.com; Steve.Greenleaf@brookfieldrenewable.com; DRMarker@bpa.gov; LTrolese@PublicGeneratingPool.com; Jon.Norman@hydrostor.ca; Jon.Norman@hydrostor.ca; YLu@SanDiego.gov; Barbara@BarkovichAndYap.com; Beth Vaughan; brian@ohmconnect.com; cbentley@gridwellconsulting.com; diana.lee@cpuc.ca.gov; Regulatory@ebce.org; Elise.ersoy@energy.ca.gov; eklinkner@cityofpasadena.net; IKearney@WEAWlaw.com; JSteffens@ci.banning.ca.us
Subject:	R.17-09-020 RA CalCCA Informal Comments Aug 17 2020
Attachments:	R.17-09-020 CalCCA Informal Comments Aug 17 2020.pdf; SL R.19-11-009 Informal Comments Aug 17 2020.pdf

To Service Lists for R.17-09-020 and R.19-11-009:

Attached please find the **CALIFORNIA COMMUNITY CHOICE ASSOCIATION INFORMAL COMMENTS ON THE LOCAL CAPACITY REDUCTION COMPENSATION MECHANISM** dated August 17, 2020. This document is being served by electronic mail in word-searchable PDF/a format.

If you have any difficulty accessing the attachment(s), please let me know.

NOTE: The recipient portion of this e-mail does not reflect all the addressees being served. The service list has been divided into separate addressee groups to avoid rejection by e-mail servers.

Regards,

Shawn-Dai Linderman

Policy Assistant
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To keep up with CCA news subscribe to our mailing list here.
You can also follow CalCCA on Twitter and LinkedIn.

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 INFORMAL COMMENTS ON THE LOCAL CAPACITY REDUCTION COMPENSATION MECHANISM

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August 17, 2020

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION INFORMAL REPLY COMMENTS ON LCR REDUCTION COMPENSATION MECHANISM

I. INTRODUCTION

The California Community Choice Association (CalCCA)[1] submits these informal reply comments in response to discussions with parties following August 3 informal workshop comments. CalCCA restates its preference for "Option 2," submitted in CalCCA's initial proposal on July 20. It further seeks to clarify certain aspects of the proposal's mechanics through responses to the specific questions posed in D.20-06-002.

II. RESPONSES TO D.20-06-002 QUESTIONS

1. How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?

CalCCA proposes that the CPE assess the effectiveness of shown resources in its comparison of the showing "alongside bid resources." The Commission directed the CPE to consider effectiveness, among other criteria, in its bid selection process.[2] Under CalCCA's proposal, the CPE would apply these effectiveness criteria in the same manner to shown resources as it does for bid resources. The CPE would then accept or reject the shown resource. Consistent with the typical solicitation process, the CPE would not have the opportunity to discount the MW or modify the price for effectiveness; the decision is binary – accept or reject. If the CPE accepts the resource, it will pay the LSE a local RA premium for the full shown Net Qualifying Capacity (NQC) at the pre-determined price (or lower shown price). If, instead, the CPE rejects the bid, the LSE would receive no local RA premium compensation.

2. How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas)?

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[1] California Community Choice Association represents the interests of 20 operational 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 José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

[2] D.20-06-002, Ordering Paragraph 14 at 95.

CalCCA proposes a premium for each local area or sub-area to ensure that the shown resources are reasonably valued and have a reasonable opportunity to "compete" with bid resources in the same local area. The premium would be set at a more aggregated level if required to mask prices of individual resources.

CalCCA's proposal makes any other granularity, such as technology, unnecessary. The CPE will consider all of these factors in evaluating both shown and bid resources using the criteria mandated by the Commission for selecting resources from the solicitation.

3. How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices.

CalCCA proposes development of a premium that will be published annually. The premium would be calculated as follows:

> <u>Year 1</u>: Use the median price from the last two quarters of Energy Division PCIA responses for both system and local RA; subtract system price from local RA price and multiply by effective MW.
>
> <u>Subsequent Years</u>: Use the median price from the last two quarters of Energy Division PCIA responses for system RA and the most reported CPE solicitation results for local RA price; subtract system RA price from local RA price and multiply by effective MW.

The pre-determined price would be made public in advance of the showing date. As CalCCA pointed out in its August 3 comments, there would be little risk to the market of publishing the premiums determined using this methodology. The system prices ultimately will be published within a year in the annual Energy Division RA Report, so there is little or no risk in revealing these prices. Making the median CPE price in the prior solicitation public also presents little risk. The median reveals nothing about the stratification of bids around the median, nor does it illuminate bid prices for bundled system/local RA resources.

An LSE could show its resource at the pre-determined price or voluntarily at a lower price to ensure a successful showing. In effect, the pre-determined price operates as a ceiling to prevent any exercise of market power through the showing process.

4. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process.

CalCCA proposes that an LSE must choose between the bid and show options. Allowing a resource to show at the pre-determined price (or voluntarily at a lower price) *before the* *solicitation* would invite gaming. An LSE could simply do both, and later revoke its showing if it gets a higher price in the bid solicitation process. Moreover, this creates unnecessary complications for the CPE, who should know the universe of shown resources before selecting bids to ensure the portfolio is optimized. Finally, the "show" then "bid" approach would create a conflict for the CPE. It would be contrary to ratepayer interests for a CPE to choose a resource in the bid process that has been made available through showing if the bid price is higher than the pre-determined price.

Allowing an LSE to show at zero after its bid is rejected in the solicitation creates similar concerns. If the CPE knows that it can procure a bid resource at zero simply by rejecting the bid, why would the CPE accept the bid? Again, to do so would only increase ratepayer costs.

Even aside from these complications, allowing an LSE to both bid and show would require further implementation rules regarding the timing and sequencing of these elections. For these reasons, the Commission should reject the bid *and* show approach.

5. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

In short, there is no need under CalCCA's proposal to develop an annual effectiveness adjustment for shown resources. The CPE will not unilaterally adjust prices from year to year for resources selected in the solicitation. It will pay the price bid for the term proposed or it will reject the bid; the notion of accepting a bid subject to future modification is antithetical to the normal IOU solicitation process. Likewise, since the CPE will be comparing the shown resources alongside the bid resources, the same principle should apply. Either the CPE accepts the resource at the price and term shown, or it rejects the resource; there is no right to modify the premium going forward as effectiveness changes.

6. How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?

This question seems unrelated to the working group's purpose and should be addressed holistically in the development of the CPE's bid evaluation criteria. CalCCA observes, however, that if a gas and preferred resource produce roughly equal value in all respects (a highly unlikely scenario), the CPE should be bound to select the preferred resource, consistent with the existing load order.

7. **In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.**

CalCCA proposes to provide the premium to LSEs who have shown their existing local RA attributes to the CPE. "Existing contracts" should be defined as contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued). The premium should be provided for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Since preferred resources are already addressed through the ongoing premium framework, this option would apply only to already-contracted fossil resources.

The IOUs propose to grant eligibility to utility-owned generation (UOG) under the "existing contract" provision. Their proposal falls unambiguously outside of the intent of D.20-06-002. CalCCA's interpretation of the decision rests on the following Commission directives:

- "For existing local <u>contracts</u>, including gas <u>contracts</u>, a working group process is established in Section 3.5 to consider treatment of these existing <u>contracts</u>." [p. 41]
- "The working group should submit a proposal on the treatment of existing <u>contracts</u>, which may include consideration of whether any proposed LCR reduction compensation mechanism should be applied to existing contracts." [p. 46]
- "The working group directed in Ordering Paragraph 5 shall also consider and submit a proposal on the treatment of existing <u>contracts</u>, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing <u>contracts</u>." [O¶ 6.]

The Commission also set clear parameters on the choices an IOU has for its resources. It directed: "A distribution utility acting as the CPE should bid its own resources into the solicitation process at their levelized fixed costs." It also specified: "A distribution utility shall have the same options as other load-serving entities in deciding whether to bid or show its resources into the central procurement entity's solicitation process." [COL 14.] In other words, the IOU will be able to show the local RA attributes of its preferred resource or energy storage to the CPE, just as other LSEs. The IOUs should also be able to show existing fossil *contracts*, subject to the terms and conditions discussed in CalCCA's proposal above.

III. OTHER DESIGN ISSUES

Term of Showing. D.20-06-002 did not address the term of a resource showing. CalCCA proposes that LSEs be permitted to show for up to whatever term is allowed for bid resources, recognizing that the term it shows will affect the CPE's evaluation of its value. The term start date could be any year within the three-year forward CPE compliance period.

Documenting the Transaction. CalCCA also proposes requiring a showing, like a bid, to be documented through a confirm under the Edison Electric Institute (EEI) Master Agreement. Shown resources should have the same level of commitment to the CPE as any bid resource.

Refinements for Administrative Ease. PG&E proposes that an LSE show *all* RA attributes in its showing to the CPE, suggesting that it would be simpler for the CPE to assess the value of bundled RA attributes than to value local RA only. In return, the LSE would receive payment of the pre-determined price (or voluntarily shown lower price) for the local RA attribute; it would maintain the system and flex value and reductions in its system and flex RA requirements. Accounting for the attributes in this way allows the submission of a resource on a single, rather than two, RA supply plans, simplifying the accounting.

IV. SUMMARY OF CALCCA PROPOSAL

Shown Resources Compared Alongside Bid Resources	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources
Annual Price Update	No annual adjustment for effectiveness
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or the LSE's lower shown price) for the local RA premium
Premium Granularity	Local area or sub-area unless aggregation up is required to mask individual resource prices; no technology differentiation in pre-determined price
Showing Term	LSE may show a resource for whatever term the CPE permits for its solicitations, with the term commencing within the current three-year compliance period
Bid/Show Election	LSE may show or bid its resource, not both
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show its local RA attributes and receive the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing owned fossil resources do not qualify for a local showing

Subject:	[R.17-09-020] PG&E's Correction to Serving Informal Comments to the LRC-RCM Working Group, August 17, 2020
Date:	Wednesday, August 19, 2020 at 5:15:16 PM Pacific Daylight Time
From:	Leung, Michael
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Attachments:	PGE_Informal_Comments_LCR-CM_Workshop_0817.pdf

To Service Lists for R.17-09-020 and R.19-11-009:

Attached, please find Pacific Gas and Electric Company's Informal Comments on the Local Capacity Requirement Reduction Compensation Mechanism (LCR-RCM), in PDF format. Please note: this filing was previously sent only to the LCR-RCM Working Group co-leads. This filing corrects that erroneous exclusion of the service lists by resending the informal comments to both service lists and the LCR-RCM Working Group co-leads.

If you have questions or technical difficulties with the attachment, please contact Lisa Wan (Lisa.Wan@pge.com).

Regards,

Michael Leung
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Case Coordinator
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Informal Reply Comments of Pacific Gas and Electric Company on the Working Group Workshop on the Local Capacity Requirement Reduction Compensation Mechanism and Treatment of Existing Contracts - Due August 17, 2020

Pacific Gas and Electric Company ("PG&E") provides the following informal reply comments on the working group for the local capacity requirement reduction compensation mechanism ("LCR-RCM") and treatment of existing contracts, co-led by PG&E and the California Community Choice Association ("CalCCA") (together, the "Co-Leads") and replies to informal comments submitted by CalCCA, Calpine Corporation ("Calpine"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDG&E") on August 3, 2020.

I. INTRODUCTION

At the LCR-RCM workshop held on July 27, 2020, CalCCA put forth an Option 2 proposal ("CalCCA Proposal") for consideration by the working group and provided further details on the Option 2 proposal through informal comments.[1] In these informal reply comments, PG&E focuses its reply comments on the CalCCA Proposal and provides additional considerations for the working group in developing a workable solution for the LCR-RCM and parameters suggested by SCE and SDG&E on the treatment of existing contracts.

II. COMMENTS ON THE CALCCA PROPOSAL

PG&E understands the CalCCA Proposal to include the following key elements: (1) the voluntarily shown option from Decision ("D.") 20-06-002 would be replaced with a "bid-in" option and, thus, would effectively remove the voluntarily shown option from the central procurement entity ("CPE") solicitation and evaluation process, (2) load serving entities ("LSE") would be required to bid only the local resource adequacy ("RA") attribute into the CPE solicitation to receive compensation under the LCR-RCM, (3) all "bid-in" resources will be evaluated simultaneously or alongside each other (e.g. as part of the entire pool of resources to

[1] CalCCA proposed two options for establishing the LCR-RCM: CalCCA Proposal #1 and CalCCA Proposal #2.

be procured by the CPE), and (4) the CPE may accept or reject the LCR-RCM eligible resources at the price and quantity shown depending on the value relative to other "bid-in" resources (e.g. there is no guaranteed premium for the LSE for LCR-RCM eligible resources).

While PG&E does not find CalCCA's Proposal to clearly meet all of the objectives in D.20-06-002, PG&E believes that the proposal is the only workable solution that has been put forth by the working group that clearly meets the objective of allowing LSEs to retain the system and flexible RA attributes and receive compensation for the local RA attribute under the hybrid procurement framework.[2] In these informal reply comments, PG&E focuses on some of the advantages and potential solutions to specific shortcomings of the CalCCA Proposal that should be considered by the California Public Utilities Commission ("Commission").

III. THE VOLUNTARILY SHOWN OPTION SHOULD CONTINUE TO BE AVAILABLE BUT WOULD NOT BE ELIGIBLE FOR THE LCR-RCM AND THE COMMISSION SHOULD CONSIDER REVISITING IOU BIDDING REQUIREMENTS IN RESPONSE TO THIS PROPOSAL

As PG&E stated in its informal comments to the working group, local resources are not equally "effective" in meeting local area reliability needs. That said, PG&E finds the process of the CalCCA Proposal for: (1) an LSE to bid only the local RA product ("Local-Only Bid") into the CPE solicitation and (2) to allow the CPE to evaluate the Local-Only Bid alongside the "bundled" system/local/flexible RA products of other resources as a workable solution to address some of the challenges associated with developing an effectiveness adjustment that would be applied to the premium price and/or the "voluntarily shown" capacity (also referred to as "must-take" capacity). Under the CalCCA Proposal, no effectiveness adjustment would need to be developed because the CPE would be allowed to accept or reject the LCR-RCM eligible resources at the price and quantity shown by appropriately valuing the "effectiveness" of the resource's potential energy-limitations relative to the entire pool of resources in meeting local area reliability needs as part of the overall evaluation and selection criteria process. PG&E

[2] The calculation can use the median price or an average price after removing market-power-inflated prices.

agrees with Calpine that this process provides LSEs with an incentive to offer competitively to the CPE to ensure that their LCR-RCM eligible resources are selected over other “bid-in” resources and that the CPE would have the discretion to not “procure” voluntarily shown resources and defer backstop procurement to the California Independent System Operator Corporation (“CAISO”) in the absence of sufficient competition.

While PG&E generally finds the CalCCA Proposal reasonable, PG&E believes that (i) all LSEs, including IOUs, should be able to avail themselves of the LCR-RCM in the same manner, and (ii) an LSE should continue to be afforded the voluntarily shown option should the LSE want to retain the system/flexible RA products for use towards its LSE-specific system and flexible RA requirements, however, the voluntarily shown option would not be eligible for compensation under the LCR-RCM.

PG&E’s concern related to item (i) in the paragraph above is that the investor-owned utilities (“IOUs”) have clear bidding requirements for participation in the CPE solicitation. D.20-06-002 states that the IOUs are to bid into the CPE solicitation at the levelized fixed costs, which refers to “the annual revenue requirement for utility-owned resources or the PPA price for contracted resources.” It is not clear how the IOUs would meet the bidding requirements for the Local-Only Bid should the IOU want to retain the system/flexible RA products for its specific system and flexible RA requirements. Accordingly, PG&E recommends that the Commission establish a separate track in the RA proceeding or identify another venue to evaluate the bidding requirements for the IOUs to participate in the Local-Only Bid option as part of CalCCA’s proposal and potentially to bid bundled RA products to the CPE to ensure that the IOUs as LSEs have the same options as other LSEs for managing their portfolios. Further, with respect to item (ii) in the paragraph above, PG&E recommends that the CalCCA Proposal be slightly modified so that the voluntarily shown option continues to be available for an LSE but the “voluntarily shown” resource would not be eligible for compensation under the LCR-RCM.

IV. ADDITIONAL CONSIDERATION IS NEEDED TO MAINTAIN THE BUNDLED RA PRODUCTS

PG&E generally agrees with Calpine that the CalCCA Proposal provides a workable solution for the CPE to evaluate all resources using "the same criteria and that the ultimate selection of the combination of ['voluntarily'] shown and bid[-in] resources to meet local RA requirements is reasonably efficient" but that the proposal may not be consistent with D.20-06-002. PG&E notes that D.20-06-002 states: "[L]ocal MWs are bundled with system MWs (and sometimes flexible MWs), for each local MW procured by the CPE there would be one MW of system capacity that is also procured (and potentially one MW of flexible capacity that is also bundled)."

Given that the CPE will be procuring an LCR-RCM eligible resource for its local RA product only, PG&E reiterates its recommendation that the working group evaluate how the "unbundling" of RA products would work or impact other parts of the RA program, specifically how the RA showings at the CAISO and Commission could be completed to maintain the bundled RA products of the resource to be consistent with D.20-06-002 and meet the objective of allowing LSEs to retain the system and flexible RA products under the hybrid procurement framework. PG&E is exploring ways to effectively implement the CalCCA Proposal in RA showings at the respective regulatory agencies with minimal impact to existing processes in the RA timeline.

V. TREATMENT OF EXISTING CONTRACTS

Within informal comments to the working group, PG&E supported legacy treatment of (1) existing resources that were procured or contracted for and (2) existing resources owned or acquired by the LSE to meet its local RA requirements prior to the consideration of a centralized procurement framework for local RA.[3] The legacy treatment would allow a resource to be

[3] PG&E notes that legacy treatment of existing contracts should not be afforded to contracts for local resources that were procured outside of that LSE's transmission access charge ("TAC") area (e.g. a northern California LSE that procured a resource within a southern California LSE's TAC) as those resources were not procured by the LSE to meet local RA requirements but were likely procured to meet the LSE's system RA requirements.

eligible for the LCR-RCM, namely for non-preferred resources. However, PG&E believes it is critical to both: (1) define a specific date by which a local resource should be deemed to be "existing" for purposes of legacy treatment and (2) to limit the term the legacy treatment would be applied. Such parameters would support California's state policy goals for decarbonization of the grid.

As commented by SCE and SDG&E, the specific date ("Legacy Treatment Date") by which a local resource would be deemed to be existing for purposes of legacy treatment shall be March 26, 2020 or June 11, 2020, respectively.[4] PG&E continues to support legacy treatment to be applied to local RA contracts executed, or owned resources that were acquired, prior to the date of issuance of D.19-02-022, March 4, 2019 as this date effectively represents the date that the Commission affirmed its intent to adopt a centralized procurement framework for local RA resources and the possibility that LSEs may no longer have a procurement obligation for local RA.

PG&E opposes CalCCA's recommendation that legacy treatment should not be given to utility-owned generation.[5] Consistent with D.20-06-002, PG&E believes the IOUs should be able to maximize ratepayer benefit for bundled service customers, as other LSEs do, and thus should have the same options that other LSEs are afforded under a potential legacy treatment of resources based on the Legacy Treatment Date.

Further, PG&E agrees with SCE that legacy treatment should be no longer than 5 years for local RA contracts executed or owned resources that were acquired prior to the Legacy Treatment Date to be eligible for compensation under the LCR-RCM.

VI. CONCLUSION

PG&E respectfully requests that these informal reply comments inform the Commission's consideration of the LCR-RCM.

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[4] March 26, 2020 is the issuance date of the Proposed Decision and June 11, 2020 is the adoption date of the Final Decision on CPE structure of local RA.
[5] July 20, 2020, CalCCA, California Community Choice Association Informal Comments on the Local Capacity Requirement Compensation Mechanism, p. 9.

Subject: R.17-09-020 and R.19-11-009_RA OIR: SCE Informal Reply Comments Regarding Working Group Workshop on LCR Reduction Compensation Mechanism and Existing Contracts August 17, 2020

Date: Monday, August 17, 2020 at 11:58:28 AM Pacific Daylight Time

From: Legal.Admin@sce.com

To: S.Tougas@CleanEnergyregResearch.com

Attachments: R1709020-SCE Informal Reply Comments on Working Group Workshop on LCR Reduction Compensation Mechanism and Existing Contracts.pdf, R1709020_Service List.pdf, R1911009_Service List.pdf

To all parties in R.17-09-020 and R.19-11-009:

Attached is Southern California Edison Company's Informal Reply Comments Regarding Working Group Workshop on Local Capacity Requirement (LCR) Reduction Compensation Mechanism and Existing Contracts August 17, 2020. This document is hereby served by electronic mail upon all parties listed in the official service lists for R.17-09-020 and R.19-11-009.

(See attached file: R1709020-SCE Informal Reply Comments on Working Group Workshop on LCR Reduction Compensation Mechanism and Existing Contracts.pdf)

(See attached file: R1709020_Service List.pdf)

(See attached file: R1911009_Service List.pdf)

Regards,

Legal Administration
Southern California Edison Company
Telephone: (626) 302-6950
Email: Legal.Admin@sce.com

Southern California Edison Company's Informal Reply Comments Regarding Working Group Workshop on Local Capacity Requirement (LCR) Reduction Compensation Mechanism and Existing Contracts
August 17, 2020

Southern California Edison Company (SCE) appreciates the opportunity to submit informal reply comments on the July 27, 2020 working group workshop regarding the LCR reduction compensation mechanism and treatment of existing resource adequacy (RA) contracts. SCE thanks the co-leads for facilitating the workshop and parties for presenting their proposals and opening comments. SCE also thanks all parties for their engagement and constructive discussion during the workshop.

SCE continues to evaluate the proposal put forth by California Community Choice Association (CalCCA) on August 3, 2020 (the CalCCA proposal).[1] SCE understands that the August 3, 2020 proposal is essentially the same as CalCCA Straw Proposal #2 presented during the July 27, 2020 Workshop.[2] SCE also understands that CalCCA is no longer pursuing its Straw Proposal #1, i.e., the "must take" option with a pre-determined premium price for showing resources because CalCCA Straw Proposal #1 was not included in the latest proposal by CalCCA. SCE also sees problems with CalCCA Straw Proposal #1. For example, this option could lead to inefficient outcomes if there are other resources that bid at lower prices, or are more economic, in meeting a local area need (or RA requirements with system and/or flexible attributes) than the "must-take" shown resources. In such a situation, the end result could be "must-take" shown resources are selected and paid for by customers at the pre-determined premium, while more economic resources are not selected, which unnecessarily increases costs to customers.

In contrast, there are merits in the CalCCA proposal presented in its informal comments (i.e., the original CalCCA Straw Proposal #2) and that proposal should be further explored.

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[1] CalCCA Informal Comments on the Local Capacity Reduction Compensation Mechanism, August 3, 2020 (CalCCA Informal Comments).

[2] CalCCA Presentation on Resource Adequacy Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) Workshop, July 27, 2020.

There are a few clarifications that should be made to the proposal as discussed below. SCE may provide additional comments as the working group process evolves.

First, it should be clarified that for a local resource that is shown by a load-serving entity (LSE) to the central procurement entity (CPE) by bidding its local attribute up to the pre-determined premium, if the resource is selected by the CPE during the solicitation, then the LSE should be paid its offer price for the shown resource.[3] If the resource is shown with an offer below the pre-determined premium, then the LSE should be paid the shown offer price, not the pre-determined premium.

Second, the option of showing a local resource without direct compensation, one of the original options described in Decision (D.) 20-06-002, should be retained. Under this option, an LSE would still be able to show its local resources to the CPE and have certainty that the shown resources will count towards meeting local requirements and lower the target for the CPE to procure through solicitations, but in that case the LSE would not receive any offer price for the local resources. While presumably the CalCCA proposal does not preclude an LSE from showing a local resource by bidding the local attribute at $0/MWh, which could arguably achieve the same certainty achieved under the original showing option, it is important that the CalCCA proposal explicitly clarify that the original showing option described in the decision will be retained. In D.20-06-002, the Commission stated when the distribution utility is acting as the CPE, it must bid its own resources at their levelized fixed costs, and that a distribution utility should have the same options as other LSEs in deciding whether to bid or show its resources into the CPE's solicitation process.[4] It is unclear how the restrictions on the distribution utilities

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3 Currently, the CalCCA proposal states: "If selected, LSE will be paid the pre-determined price for the shown resource." CalCCA Informal Comments at 10.

4 *See* D.20-06-002 at Ordering Paragraph 11 ("A distribution utility that is acting in its capacity as a central procurement entity (CPE) shall bid its own resources, that are not already allocated to all benefiting customers, into the solicitation process at their levelized fixed costs. A distribution utility that is not acting in its capacity as the CPE is not required to bid its resources into another CPE's solicitation at their levelized fixed costs."); Ordering Paragraph 9 ("A distribution utility shall have the same options as other load-serving entities in deciding whether to bid or show its resources into the central procurement entity's solicitation process.").

bidding their own resources at their levelized fixed costs would apply in a situation where the "show" option includes an offer price for the local attributes. To avoid any confusion and complications, the CalCCA proposal should explicitly clarify that the original showing option as described in the decision (i.e., to show with no offer price or premium) will be retained. Further, the original showing option should be available to all LSEs, as intended under the decision.

SCE appreciates the opportunity to comment and looks forward to further discussion and parties' consideration of the issues outlined above.

APPENDIX F

AUGUST 26, 2020 INFORMAL COMMENTS ON DRAFT REPORT

Subject: AReM's Comments on Draft Report -- LCR Reduction Compensation Mechanism
Date: Wednesday, August 26, 2020 at 2:01:23 PM Pacific Daylight Time
From: Sue Mara
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Attachments: (DRAFT) Co-Leads Working Group Report on LCR RCM and Treatment of Existing Contracts--AReM's comments.docx

To Co-Leads of Working Group on LCR Reduction Compensation Mechanism and Treatment of Existing Contracts:

As requested in your e-mail of August 21, 2020, attached are the comments of the Alliance for Retail Energy Markets (AReM) on the Draft Report.

These comments have also been sent to the service lists for R.17-09-020 and R.19-11-009, as you requested.

Because of the size of the combined service lists, these comments have been sent in two transmissions.

Please contact me with any questions.

Regards,

Sue Mara
On Behalf of AReM

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ATTACHMENT 1 TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) TRACK 3.A WORKING GROUP REPORT ON CONSENSUS AND NON-CONSENSUS ITEMS REGARDING DEVELOPMENT OF LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND PROPOSAL ON TREATMENT OF EXISTING CONTRACTS

WORKING GROUP REPORT

[TABLE OF CONTENTS TO BE INSERTED]

Working Group Report on Consensus and Non-Consensus Items Regarding Development of Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Proposal on Treatment of Existing Contracts

I. Background

A. Procedural Background and Scope

Decision (D.) 20-06-002 adopts implementation details for the central procurement of multi-year local resource adequacy (RA) to begin for the 2023 compliance year in the Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) distribution service areas, including identifying PG&E and SCE as the central procurement entities (CPE) for their respective distribution service areas and adopting a hybrid central procurement framework.[1] The framework places full local RA procurement responsibility on behalf of all load serving entities (LSE) on the CPE, and LSEs no longer receive individual local requirements.[2] LSEs that have procured local resources may "(1) show the resource to reduce the central procurement entity's (CPE) overall local procurement obligation and retain 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."[3] Under the "show" option, the LSE does not receive one-for-one credit for its local resources.[4]

In adopting the hybrid central procurement framework, the California Public Utilities Commission (Commission) found that, even without a financial crediting mechanism, the framework does not disincentivize procurement of local resources because LSEs procure local

[1] D.20-06-002 at 1, Ordering Paragraphs 2-4.
[2] *Id*. at 22-23, Ordering Paragraph 3.
[3] *Id*. at 23, Ordering Paragraph 4.
[4] *Id*. at 23.

resources for many reasons beyond the local RA value.[5] The Commission recognized, however, that "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas."[6] To that end, the Commission committed to developing ~~a~~ **an "LCR reduction compensation mechanism,** ~~**"financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value" (LCR RCM),**~~ if details can be assessed and developed[sjm1]."[7] **The Commission defined "LCR reduction compensation mechanism" (LCR RCM) as a "financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value."[8]** To develop such a mechanism, the Commission directed a working group (WG) co-led by CalCCA and either PG&E or SCE.[9] The Commission also included within the scope of the WG issues related to treatment of existing contracts, including potential application of the LCR RCM to these contracts.[10] The Commission further required the co-leads to file a WG report on consensus and non-consensus items (Report) in this proceeding by September 1, 2020. In addition, the assigned Commissioner in this proceeding issued the *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling*, dated July 7, 2020 (Amended Scoping Memo), designating evaluation of an LCR RCM as an issue in Track 3.A and requiring WG reports and proposals from parties to be filed on September 1, 2020.

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5 *Id*. at 40-41, 72.
6 *Id*. at 42, 72.
7 *Id*., at 43.
8 *Id*, at 42.
9 *Id*. at Ordering Paragraph 5.
10 *Id*. at 46, 75 and Ordering Paragraph 6.

In both D.20-06-002 and the Amended Scoping Memo, the Commission identified four specific issues to be addressed by the Report:[11]

a. How granular the premium should be (*e.g.*, should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);

b. How to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

c. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process; and

d. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

In addition, the Commission directed in D.20-06-002 that the Report "address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources."[12] D.20-06-002 also requires the WG to (i) "consider and submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing contracts"[13] and (ii) consider how the CPE will incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small."[14] The Report must also address consensus and non-consensus items regarding treatment of existing contracts.[15]

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[11] *Id.* at Ordering Paragraph 5.

[12] *Id.* at Ordering Paragraph 5. The Amended Scoping Memo includes a similar requirement. Amended Scoping Memo at 3.

[13] *Id.* at Ordering Paragraph 6.

[14] *Id.* at pp. 44-45. The four issues identified above (a.-d.) and the three issues identified in this paragraph (i.e. in the first sentence and romanettes (i) and (ii) of the second sentence) are referred to herein as the "7 Issues." The 7 Issues are also outlined in the email attached as Exhibit A.

[15] *Ibid*.

Using this guidance, CalCCA and PG&E, serving as WG co-leads, sent an email to the service list on July 6, 2020, soliciting initial input from stakeholders through informal comments submitted on July 20, 2020, and seeking participation by other stakeholders with an interest in presenting at a WG workshop on the identified issues set for July 27, 2020.[16] Eight parties submitted informal comments on the 7 Issues on July 20, 2020 ahead of the July 27, 2020 WG workshop. These informal comments are attached as Exhibit B to this Report. Three parties (PG&E, CalCCA, and San Diego Gas & Electric Company (SDG&E)) expressed interest in presenting at the WG workshop. The co-leads facilitated the WG workshop by WebEx on July 27, 2020, beginning at 10:00 a.m. The co-leads jointly presented a review of the 7 Issues identified in D.20-06-002 and initial informal comments on the 7 Issues. Additionally, PG&E made a presentation as a participant in the WG to address pending issues. CalCCA also presented as a WG participant, offering two proposals. The only other party presenting a proposal was SDG&E. These presentations are attached as Exhibit C. WG participants submitted informal comments and replies regarding the WG workshop on August 3, 2020, attached as Exhibit D, and on August 17, 2020, attached as Exhibit E, respectively. A draft of the Report was circulated to WG participants on [August 21, 2020], with informal comments on the draft Report submitted on [August 26, 2020] and attached here as Exhibit F.

The workshop and parties' informal comments have helped inform this Report.

B. Topics Expressly Excluded from Scope

The Commission expressly identified certain topics as out-of-scope.[17] They include:

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16 The email to the service list laying out the WG schedule is attached as Exhibit A.

17 D.20-06-002 at 43 ("The Commission is not open to considering a one-for-one credit, CalCCA's proposed financial credit mechanism, or a credit mechanism for fossil fuel resources (other than potentially for existing grandfathered contracts).").

1. One-for-one credit mechanism for local RA that does not account for relative effectiveness of shown resources relative to bid resources;[18]

2. Ex-post price premium based on the average price paid by the CPE for resources in the local area for which a resource is shown;[19]

3. Credit mechanism for fossil fuel resources (other than potentially for existing contracts);[20] and

4. An LCR RCM mechanism for the SDG&E Transmission Access Charge (TAC) area, where a CPE will not be designated. [21]

Stakeholders generally adhered to this guidance in offering proposals presented through the WG process and described in this Report.

C. Schedule of Completed Activities

The co-leads scheduled and completed the following WG activities:

Date	Activity	Status
July 6, 2020	Co-leads circulated notice to the service lists of WG co-leads and WG schedule, including workshop, and request for informal comments on 7 Issues outlined in D.20-06-002 on pages 43-45 and in Ordering Paragraphs 5 and 6.	Complete
July 17, 2020	Co-leads circulated notice of workshop date and call-in information to the service lists.	Complete
July 20, 2020	Parties submitted informal comments to the service lists in response to the co-leads' request on 7 Issues outlined in D.20-06-002 and notified co-leads of intent to present at workshop.	Complete
July 24, 2020	Co-leads circulated notice of agenda and presentation materials for the virtual workshop to service lists.	Complete

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18 *Id*. at 41.
19 *Id*. at 42.
20 *Id*. at 41.
21 *Id*. at Conclusion of Law 6.

July 27, 2020	Co-leads hosted a virtual workshop on WebEx on LCR RCM and the treatment of existing contracts.	Complete
July 30, 2020	Co-leads again circulated presentations from virtual workshop to workshop participants, in addition to a matrix for parties to utilize in developing informal comments on the workshop.	Complete
July 31, 2020	Co-leads circulated updated schedule for WG to the service lists, including dates for informal reply comments on workshop, issuance of a draft Report, and informal comments on the draft Report.	Complete
August 3, 2020	Parties submitted informal comments on the workshop to co-leads, which were circulated to the service lists on August 4, 2020.	Complete
August 17, 2020	Parties submitted informal reply comments on the August 3 informal comments to the service lists (PG&E's informal reply comments were sent to the co-leads on August 17, 2020, and to the service lists on August 19, 2020).	Complete
August 20, 2020	Co-leads circulated an updated schedule for the WG to the service lists	Complete
August 21, 2020	Co-leads served a draft Report to the service lists for comment.	Complete
August 26, 2020	Parties submitted informal comments on the draft Report to the service lists.	[Complete]
September 1, 2020	Co-leads filed and served Report.	[Complete]

II. Guiding Principles and Objectives

The co-leads presented their views and interpretations on guiding principles and objectives in the July 27, 2020, workshop presentations.

A. Guidance from D.20-06-002

Drawing from D.20-06-002, the co-leads identified the following explicit guidance provided by the Commission, with the corresponding page number or ordering paragraph (OP) in brackets:

Effectiveness:

1. The LCR RCM cannot provide a "one for one" premium as CalCCA proposed without considering effectiveness. [p. 41]
2. The LCR RCM must address "local effectiveness" and "use limitations" of the shown resource to align the financial compensation with the actual LCR MW reduction the resource provided. [p. 42, OP 5]
3. The WG should consider how to adjust payments to an LSE "from year to year to account for changes in the effectiveness of the resource reducing local requirements." [OP 5.d.]
4. CPE selection criteria must include (1) "Local effectiveness factors, as published in the California Independent System Operator's Local Capacity Requirement Technical Studies" [OP 14.b.] and "Energy-use limitations" [OP 14.h.]

Least-Cost, Best-Fit:

a. "Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSE's seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE" [p. 42]
b. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]
c. "[E]nsures that ratepayers are: (1) only compensating resources to the extent they provide ratepayer value…" [p. 43]

Premium Determination and Market Power Issues:

1. The LCR RCM should "only compensate [] LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs" [p. 43]
2. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]
3. A "benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums" [p. 42]
4. "To the extent that market power inflates local area capacity prices, an ex post benchmark would exacerbate this problem by providing inflated prices to local resources shown by LSEs" [p. 42]

5. The WG must determine "[h]ow to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices." [OP 5.b]

Preferred Resource Development in Local Areas

1. "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas." [p. 41]

B. PG&E Proposed Principles

Based on the guidance in D.20-06-002, PG&E outlined the following four recommended principles for the LCR RCM in its workshop presentation included in Exhibit C:

- The LCR RCM should:
  - Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;
  - Reflect the effectiveness of a resource at meeting reliability requirements to prevent "leaning" by LSEs;
  - Result in lower total costs to customers without sacrificing local area reliability; and
  - Not be reflective of market power and/or introduce gaming opportunities but may reflect a "premium" based on the additional cost of developing resources in local areas.

WG participants also provided recommendations and comments on guiding principles. The Alliance for Retail Energy Markets (AReM) proposed the following principles in the evaluation of the need and structure for any such compensation mechanism:

- No CPE Over-procurement - The ability for an LSE to receive an LCR RCM payment from the CPE must not result in over-procurement by the CPE with those costs spread among all LSEs;
- Cost Causation – Customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; costs should not be spread to other LSEs or their customers;

- Premiums Paid for Shown Resources Must Be Aligned with the Auction – LSEs with resource **types** **that are** worth a premium to the CPE should be eligible for compensation up to that premium ~~not more~~**, *i.e.*, if the CPE auction awards a higher RA price to energy storage, any LSE-shown resource that is energy storage should be eligible for the LCR RCM premium that does not exceed the premium paid for such resources in the auction**; and

- Payment Length for Show Resources Must Be Aligned with the Local RA Requirement – The number of years an LSE is eligible for an LCR RCM payment should not be longer than up to three years – the term of the Local RA requirement.

California Energy Storage Alliance (CESA), in addition to responses to the specific 7 Issues presented, also suggested that the WG should:

- consider pathways to maintain the load forecast adjustment process that is specific to an LSE and reflected in their pro rata share of the collective local RA requirements, and

- clarify and discuss the implications of the CPE buying all RA attributes if selected.

III. Description of Proposals

A. CalCCA Proposals

1. CalCCA Option #1

CalCCA's initial proposal, presented in its July 20, 2020, informal comments, advanced a CPE "must take" model. The model evolved as a result of the workshop and Parties' comments, however, into a refined "Option #1" proposal presented in CalCCA's July 27, 2020, comments. CalCCA does not recommend adoption of this approach but prefers its "Option #2" described below.

Under the must-take model, the CPE would be bound to take any local RA attributes from preferred or energy storage resources shown by an LSE. The price would be determined using the following formula:

Year 1: Use the median price from the last four quarters of Energy Division Power Charge Indifference Adjustment (PCIA) responses for both system and local RA; subtract system RA price from local RA and multiply by effective megawatt (MW)

Subsequent Years: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

This formulation removes the risk of market power influence by relying on the *median* CPE bid price rather than an *average* bid price. The median price is also unlikely to suggest pricing to future bidders, which an average price would do.

The number of MW shown by the LSE would be adjusted for effectiveness, using one of two methods. The first method would rely on published California Independent System Operator Corporation (CAISO) effectiveness factors, scaling a resource's effectiveness to the average effectiveness procured by the CPE in that specific local area. Because these factors do not fairly represent the value of resources, due to their focus on a limited subset of constraints, CalCCA did not favor this approach. The second method would rely on a yet-to-be determined methodology using data regarding peak contribution of particular technologies in specific local areas and data underlying the CAISO's identified storage need in its annual Local Capacity Technical Study. CalCCA pointed out, however, that developing these technology-specific methodologies would be time consuming and would, at best, provide only rough justice in determining the showing value.

CalCCA does not support adoption of Option #1 due to the complexity of developing reasonable effectiveness calculations. In addition, it is difficult to square a CPE "must-take" model with the directive in D.20-06-002 that shown resources must be "evaluated alongside bid resources."

2. CalCCA Option #2

CalCCA advances its Option #2 as the preferred methodology for the LCR RCM. Unlike Option #1, the CPE would not be bound to accept all shown resources but could reject them after considering their value "alongside bid resources." The "pre-determined price" calculation would be the same as Option #1:

> Year 1: Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> Subsequent Years: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

The only difference is that an LSE could choose to show its resources to the CPE for local credit at a price lower than the pre-determined price if desired.

The primary benefit of this approach, however, is administrative simplicity. Option #2 does not require further work to develop highly technical, technology-specific effectiveness values. Instead, it relies on the guidelines the CPE will use to evaluate bid resources. In other words, the CPE would apply the same methodology or considerations to *bid* and *shown local RA* resources in comparing their value.

Beyond these fundamental features, CalCCA addressed term and documentation of showings. Resources committed through a showing would have a three-year commitment where the term start date could be any year within the three-year forward compliance period. The showing (like bid) would be documented through a confirm under the Edison Electric Institute (EEI) Master Agreement.

3. CalCCA Proposal on Treatment of Existing Contracts

In essence, since preferred and storage resources are covered by the showing option, the legacy treatment for existing contracts identified by D.20-06-002 LCR RCM would only apply to existing fossil contracts. The Commission did not extend this same authority for an investor owned utility (IOU) to show fossil utility owned generation (UOG). As stated in D.20-06-002, existing fossil UOG would be required to bid into the CPE solicitation, and bid UOG would receive Cost Allocation Mechanism (CAM) treatment.[22]

CalCCA proposes that existing fossil contracts receive legacy treatment for five years from the implementation of the CPE. Legacy contracts will include only resources that are currently online and were contracted by an LSE on or before June 11, 2020 (the date D.20-06-002 was issued).

Summary of CalCCA Option #2 LCR RCM Recommendation	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	If selected, LSE will be paid the showing price (pre-determined price or below) without annual adjustment for effectiveness, like bid resources.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose (see §b. above.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or lower if the LSE showed at a lower price) for the shown resource.
Premium Granularity	Price is differentiated by local area or sub-area, unless aggregation up is required to mask individual resource prices; not technology-specific prices.
Showing Term	LSE may show a resource for a term of up to three years, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show for the local premium for the

[22] D.20-06-002 at 48.

	lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing UOG "resources" do not qualify for a local showing.

B. SDG&E Proposal

SDG&E developed a proposal, included it in their July 20, 2020 comments, and presented the proposal at the July 27, 2020 workshop. SDG&E's proposal addressed local premium, effectiveness factors, duration, and cost-allocation.

On the local premium, SDG&E proposed that the CPE utilize the relevant Power Cost Indifference Adjustment (PCIA) System RA Market Price Benchmark (MPB) for its area, either NP-15 or SP-15 for the compliance year. SDG&E noted that the System RA MPB is typically available in November prior to the compliance year. SDG&E suggested consideration of the weighted average price of Local resources that were contracted by the CPE for the compliance year. This means that the CPE must identify the specific cost related to RA capacity procured if it procured other attributes, such as Flexible RA or energy tolling, which is necessary to ensure an apples-to-apples comparison. SDG&E also explored using the PCIA Local MPB, however it was unclear how the CPE procurement of Local resources would impact the PCIA Local MPB calculation. Therefore, SDG&E recommended using prices relevant to CPE procurement. SDG&E also maintained that both values could be made publicly available in November after the CPE has finished its procurement along with the publication of the annual PCIA MPBs.

On effectiveness, SDG&E argued that effectiveness factors should be guided by the CAISO and the annual Local Capacity Technical Study (LCTS). SDG&E proposed that the effectiveness factors for all shown resources be calculated based on the percentage resulting from the local or sub-area LCR divided by the total amount of capacity shown and CPE procured capacity. SDG&E provided the example that if the LCR is 100 MWs and 40 MWs were shown by LSEs, and 80 MWs were procured by the CPE, the percentage would be 100 MW / 120 MW, or 83.33 percent. LSEs that showed the total of 40 MWs would receive a credit of approximately 33.33 MWs.

In terms of duration, SDG&E proposed that the resources would be shown annually on a three-year rolling basis.

For cost-allocation, SDG&E proposed that the premium associated with the shown local RA capacity would reduce the costs allocated to the LSE by the CPE for the procurement.

C. PG&E Presentation and Proposals

While PG&E did not present a full proposal at the July 27, 2020 workshop, PG&E's presentation included proposed guiding principles for the LCR RCM, detailed above in Section II and repeated here for convenience:

- The LCR RCM should:
    - Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;
    - Reflect the effectiveness of a resource at meeting reliability requirements to prevent "leaning" by LSEs;
    - Result in lower total costs to customers without sacrificing local area reliability; and
    - Not be reflective of market power and/or introduce gaming opportunities but may reflect a "premium" based on the additional cost of developing resources in local areas.

PG&E's presentation explained that PG&E had not identified a mechanism for developing a price that clearly met these proposed guiding principles. In attempting to establish an appropriate local price, PG&E considered two options: cost-based and market-based. PG&E discussed how each of these prices could be derived and outlined the drawbacks of each option.

PG&E also proposed that the LCR RCM premium should be as granular as possible in order to send the correct market signals.

PG&E further explained its view that any "workable" solution must be paired with a transparent and appropriate effectiveness adjustment and demonstration of reduction in total costs to customers. PG&E's presentation provided information regarding the complexity and potential infeasibility of developing effectiveness adjustments using CAISO effectiveness factors, as well as other measures of effectiveness that could be explored.

PG&E concluded its presentation by stating that the LCR RCM should not result in an increase in total costs to customers. In other words, resources paid through this mechanism must be lower cost than its alternative, and the mechanism must not be game-able.

In addition, PG&E utilized the July 20, 2020, informal comments to provide its proposals with respect to treatment of existing contracts and existing owned resources. First, PG&E proposed that legacy treatment of existing contracts not be afforded to contracts for local resources that were procured outside of an LSE's transmission access charge (TAC) area (e.g. a northern California LSE that procured a resource within a southern California LSE's TAC), as those resources were not procured by the LSE to meet local RA requirements, but were likely procured to meet the LSE's system RA requirements. PG&E also proposed that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired, prior to the date of issuance of D.19-02-022, March 4, 2019 (i.e. when the Commission affirmed its intent to adopt a centralized procurement framework for local RA resources and the possibility that LSEs may no longer have a procurement obligation for local RA). PG&E also proposed that legacy treatment not be applied for the full term of an existing contract or the life of an existing owned resource.

IV. Consensus and Non-Consensus Items

A. Matrix of party positions

As part of the WG process, the co-leads developed a matrix of party positions that covers key questions, including effectiveness, granularity, transparency, bidding issues, annual adjustments, the evaluation process, and shows where there is consensus and non-consensus among parties. The matrix was distributed to workshop participants on July 30, 2020, and parties provided edits to the matrix as part of informal comments submitted on August 3, 2020. The matrix has been updated to incorporate edits submitted on August 3, 2020, and is included in this Report as Exhibit G.

B. Summary of Consensus and Non-Consensus Items for the 7 Issues

1. Cost-effectiveness

While some parties stated that the mechanism should not provide compensation if the resource does not provide value (CalPA) or does not reduce costs (PG&E), other parties argued that cost-effectiveness should not be in scope (CEDMC). Others raised feasibility of the mechanism if CAISO would need to provide information on effectiveness (SCE, SDG&E). Others argued that the CPE should produce multiple portfolios, akin to the transmission alternative portfolios the CAISO creates in the Transmission Planning Process, as a means to address cost-effectiveness (CESA).

With respect to how the mechanism should address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources, six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the topic should be within the scope of the mechanism and one party (CEDMC) stated that it should be outside of the scope of the mechanism.

PG&E and CESA expressed that a resource should demonstrate its effectiveness to receive compensation. CESA looks to have the assessment incorporate non-quantitative criteria, whereas PG&E looks to have only quantitative criteria used.

Six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the effectiveness adjustments could be determined by the CAISO through various mechanisms. The specific actions suggested by the parties varied, ranging from: adjustments to NQC values (PG&E), determination of effectiveness factors (SCE), using the Local Capacity Technical Study (SDG&E), and developing a stakeholder process for determining the appropriate mechanism (CalCCA).

CalCCA's final proposal (Option #2) left the question to the CPE. The CPE is required to take effectiveness into account in selecting bids from its solicitations. Since CalCCA's proposal (Option #2) contemplates a comparison of shown preferred resources alongside bid resources, CalCCA submits that the CPE should apply the same criteria – whatever they may be – to both bid and shown resources.

2. Premium granularity

There was a broad spectrum of perspectives on premium granularity. Some parties argued that the premium should be dependent on the data available; for example, it could be sub-area, local area, or TAC-wide area (SCE). Others argued for premiums for each resource technology type (CalPA) or by resource type, location, or operational characteristics (CEDMC), or based on location, including disadvantaged communities (DACs), GHG emissions reduction, and market power mitigation (CESA).

With respect to how granular the premium should be, three parties stated that the price premiums should be differentiated by local areas or sub-local areas (CalCCA, PG&E, and SDG&E) and one party stated that it should be differentiated by the TAC-wide area (SCE) unless a higher level of aggregation was required to mask the price of individual resource prices. SDG&E stated that the complexity of developing individual premiums for the various types of resources makes the task infeasible.

One party stated that a series of premiums should be stacked to arrive at the final premium for a resource (e.g., closer-to-load, within a DAC, GHG emission reduction, and offers market power mitigation) (CESA). An additional party referenced a premium for a resource being located within a DAC (CEDMC).

3. Transparency of premium

Parties broadly supported as much transparency as possible, while still protecting market-sensitive information. Parties presented numerous ideas on how and when data should be presented. For instance, PG&E advocated for aggregating data upfront and making more detailed data available after sufficient time had passed. CalPA argued for posting the premiums to the service list and CESA argued that premiums should be made available by resource class. SDG&E argued that advance knowledge of the premium is not necessary since LSEs could still show the resource if the offer is not selected by the CPE.

CalCCA observed that its proposal would allow for full transparency of the predetermined price. Neither source of data required for the calculation -- the median bid price from the last CPE solicitation and the aggregated RA prices reported to Energy Division -- presents concerns regarding market sensitivity. The Energy Division prices are made public annually, and the median CPE price would reveal very little about the stratification of bids actually accepted by the CPE.

4. Bidding issues

On the issue of whether the mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation, both PG&E and CalCCA argued that the LSE would need to choose between voluntarily showing (for mechanism eligibility) and bidding / showing as part of the solicitation process. CESA argued that the LSE should not be precluded from also bidding and showing. SCE recommended that this topic be further discussed in workshops to address issues of gaming risk.

CalCCA also proposes a price formula for the pre-determined price. The "pre-determined price" calculation would be calculated as follows:

> Year 1: Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> Subsequent Years: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

An LSE could choose to show its preferred or energy storage resources to the CPE for local credit at a price lower than the pre-determined price if desired.

5. Annual adjustments to local compensation

Parties had differing views on how frequently the mechanism should be adjusted. PG&E advocated that the premium should be updated annually to reflect the most recent CAISO Local Capacity Technical Study Report. CESA argued that an annual adjustment would not be necessary. Others argued that annual adjustments would ultimately depend on the details of the mechanism (SCE).

Because CalCCA proposes comparison of the shown resource alongside bid resources, as D.20-06-002 requires, CalCCA proposes no annual adjustment to the compensation. Bid resources are not adjusted annually for effectiveness but are paid as bid. In the same way, shown resources should be paid for the term of the showing at the pre-determined price (or below).

6. Bid evaluation process

On the question of how the CPE should incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources, there were several disparate ideas. SCE argued that the question should be addressed in CPE implementation as it relates to the bid selection process and bid selection criteria and how the CPE will fairly implement the least-cost-best-fit procurement criteria. CEDMC argued that both qualitative and quantitative criteria be considered, and preferred resources should be favored over fossil-fueled resources. CESA argued that the criteria should link to integrated-resource-plan-identified future long-term procurement needs in local or sub-local areas and adhere to the loading order and SB 1136 statutory requirements to the greatest extent possible.

7. Treatment of existing contracts

There were several proposals relating to the treatment of existing contracts that spanned a cutoff date for qualification, the period over which a contract should qualify, and whether UOG should qualify.

On the issue of a cutoff date, PG&E and SCE advocated that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired prior to the date of issuance of D.19-02-022, March 4, 2019. CalCCA argued that the mechanism should be applied to existing contracts entered into by an LSE on or before June 11, 2020.

On the issue of the period over which a contract should qualify, SCE argued that it should be for up to a five-year term length. PG&E also stated that legacy treatment should not apply for the full term of the existing contract or owned resource. CalCCA recommends that the term be consistent with the terms sought for bid resources.

Lastly, on the issue of UOG, CalCCA argued that UOG should not be eligible, while PG&E advocated for eligibility for UOG.

V. Consensus and Non-Consensus Around Full LCR RCM Proposals

A. CalCCA's Proposal (Option #2)

CalCCA offered a complete proposal (Option #2) for the LCR RCM, summarized in their comments as follows:

Shown Resources Compared Alongside Bid Resources	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	No annual adjustment for effectiveness.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or the LSE's lower shown price) for the local RA premium.
Premium Granularity	Local area or sub-area unless aggregation up is required to mask individual resource prices; no technology differentiation in pre-determined price.
Showing Term	LSE may show a resource for whatever term the CPE permits for its solicitations, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show its local RA attributes and receive the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing owned fossil resources do not qualify for a local showing.

Several parties expressed interest in this proposal, although there was not broad consensus reached from all parties involved in the WG. Both Calpine Corporation and AReM submitted informal comments questioning the concept of permitting bids outside of the auction process and suggesting that there should be "full flexibility to specify the prices at which shown resources will be compared to bid resources" in the CPE's auction to provide LSEs "incentives to offer competitively to ensure that their resources are selected over offered resources." AReM observed that all options for a compensation mechanism have risks for market power and gaming and questioned "if the limited potential benefits warrant moving forward with any compensation mechanism."

PG&E submitted comments in reply to CalCCA's proposal (Option #2) stating that PG&E did not find that the proposal clearly meets all of the objectives in D.20-06-002; however, PG&E believes it is reasonable and the only workable solution that has been put forth by the WG that clearly meets the objective of allowing LSEs to retain the system and flexible RA attributes and receive compensation for the local RA attribute under the hybrid procurement framework. If the Commission is willing to consider this proposal, PG&E believes that (i) all LSEs, including IOUs, should be able to avail themselves of the LCR RCM in the same manner (which requires the Commission to revisit IOU bidding requirements in D.20-06-002 in a new track of the RA proceeding or identify another venue to evaluate the bidding requirements for IOUs to participate in the LCR RCM proposed by CalCCA in Option #2), and (ii) LSEs should continue to be afforded the "voluntarily shown" option, without compensation under the LCR RCM, should LSEs want to retain the system/flexible RA products for use toward its LSE-specific system and flexible RA requirements.

SCE also submitted comments in reply to CalCCA's proposal (Option #2) stating that there are merits to the proposal, and it should be further explored. SCE recommended a few clarifications to the proposal, including (i) if a shown resource is selected by the CPE during the solicitation, then the LSE should be paid its offer price for the shown resource, not the pre-determined premium, and (ii) the option of showing a local resource without direct compensation should be retained and made available to all LSEs.

B. SDG&E's Proposal

As described in Section III.B, SDG&E also provided a full proposal on the LCR RCM. PG&E submitted comments on SDG&E's proposal expressing concerns that the proposed methodology does not appropriately addresses cost effectiveness concerns. PG&E believes that it may overestimate voluntarily shown resources, which may result in customers paying for resources that do not provide any ratepayer value or any local area reliability benefits to the system. Additionally, PG&E has concerns with SDG&E's proposal on local premium price, as this methodology is similar to the financial crediting mechanism proposed by CalCCA in Rulemaking 17-09-020 that was rejected by the Commission and specifically excluded from the scope of consideration in this Track.

<u>Exhibits</u>

Exhibit A: July 6, 2020 Service Email

Exhibit B: July 20, 2020 Informal Comments

Exhibit C: July 27, 2020 WG Workshop Presentations

Exhibit D: August 3, 2020 Informal Comments

Exhibit E: August 17, 2020 Informal Reply Comments

Exhibit F: August 26, 2020 Informal Comments on Draft Report

Exhibit G: Final Matrix of Party Positions

Subject:	R.19-11-009: CESA's Proposed Revisions to (DRAFT) Co-Leads Working Group Report on LCR RCM and Treatment of Existing Contracts
Date:	Wednesday, August 26, 2020 at 4:04:57 PM Pacific Daylight Time
From:	Jin Noh (CESA)
To:	evelyn@cal-cca.org, ccsong@cleanpoweralliance.com, 'DEmerson@SonomaCleanPower.org', 'MBrandt@ebce.org', s.tougas@CleanEnergyRegResearch.com, Erica.Brown@pge.com, Rhett.Kikuyama@pge.com, Lisa.Wan@pge.com, Noelle.Formosa@pge.com
Attachments:	image001.jpg, (DRAFT) Co-Leads Working Group Report on LCR RCM and Treatment of Existing Contracts - CESA.docx

To the Working Group Co-Leads and parties of R.19-11-009:

As requested, please find attached minor proposed revisions from CESA on the Co-Leads Working Group Report on LCR RCM and Treatment of Existing Contracts. Per the instructions, this is being served to the service lists of R.17-09-020 and R.19-11-009.

Jin Noh
Senior Policy Manager
California Energy Storage Alliance

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ATTACHMENT 1 TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) TRACK 3.A WORKING GROUP REPORT ON CONSENSUS AND NON-CONSENSUS ITEMS REGARDING DEVELOPMENT OF LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND PROPOSAL ON TREATMENT OF EXISTING CONTRACTS

WORKING GROUP REPORT

[TABLE OF CONTENTS TO BE INSERTED]

Working Group Report on Consensus and Non-Consensus Items Regarding Development of Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Proposal on Treatment of Existing Contracts

I. Background

A. Procedural Background and Scope

Decision (D.) 20-06-002 adopts implementation details for the central procurement of multi-year local resource adequacy (RA) to begin for the 2023 compliance year in the Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) distribution service areas, including identifying PG&E and SCE as the central procurement entities (CPE) for their respective distribution service areas and adopting a hybrid central procurement framework.[1] The framework places full local RA procurement responsibility on behalf of all load serving entities (LSE) on the CPE, and LSEs no longer receive individual local requirements.[2] LSEs that have procured local resources may "(1) show the resource to reduce the central procurement entity's (CPE) overall local procurement obligation and retain 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."[3] Under the "show" option, the LSE does not receive one-for-one credit for its local resources.[4]

In adopting the hybrid central procurement framework, the California Public Utilities Commission (Commission) found that, even without a financial crediting mechanism, the framework does not disincentivize procurement of local resources because LSEs procure local

[1] D.20-06-002 at 1, Ordering Paragraphs 2-4.
[2] *Id*. at 22-23, Ordering Paragraph 3.
[3] *Id*. at 23, Ordering Paragraph 4.
[4] *Id*. at 23.

resources for many reasons beyond the local RA value.[5] The Commission recognized, however, that "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas."[6] To that end, the Commission committed to developing a "financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value" (LCR RCM), if details can be assessed and developed.[7] To develop such a mechanism, the Commission directed a working group (WG) co-led by CalCCA and either PG&E or SCE.[8] The Commission also included within the scope of the WG issues related to treatment of existing contracts, including potential application of the LCR RCM to these contracts.[9] The Commission further required the co-leads to file a WG report on consensus and non-consensus items (Report) in this proceeding by September 1, 2020. In addition, the assigned Commissioner in this proceeding issued the *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling*, dated July 7, 2020 (Amended Scoping Memo), designating evaluation of an LCR RCM as an issue in Track 3.A and requiring WG reports and proposals from parties to be filed on September 1, 2020.

In both D.20-06-002 and the Amended Scoping Memo, the Commission identified four specific issues to be addressed by the Report:[10]

a. How granular the premium should be (*e.g.*, should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);

b. How to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

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5 *Id*. at 40-41, 72.
6 *Id*. at 42, 72.
7 *Id*., at 43.
8 *Id*. at Ordering Paragraph 5.
9 *Id*. at 46, 75 and Ordering Paragraph 6.
10 *Id*. at Ordering Paragraph 5.

c. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process; and

d. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

In addition, the Commission directed in D.20-06-002 that the Report "address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources."[11] D.20-06-002 also requires the WG to (i) "consider and submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing contracts"[12] and (ii) consider how the CPE will incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small."[13] The Report must also address consensus and non-consensus items regarding treatment of existing contracts.[14]

Using this guidance, CalCCA and PG&E, serving as WG co-leads, sent an email to the service list on July 6, 2020, soliciting initial input from stakeholders through informal comments submitted on July 20, 2020, and seeking participation by other stakeholders with an interest in presenting at a WG workshop on the identified issues set for July 27, 2020.[15] Eight parties submitted informal comments on the 7 Issues on July 20, 2020 ahead of the July 27, 2020 WG

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11 *Id.* at Ordering Paragraph 5. The Amended Scoping Memo includes a similar requirement. Amended Scoping Memo at 3.

12 *Id.* at Ordering Paragraph 6.

13 *Id*. at pp. 44-45. The four issues identified above (a.-d.) and the three issues identified in this paragraph (i.e. in the first sentence and romanettes (i) and (ii) of the second sentence) are referred to herein as the "7 Issues." The 7 Issues are also outlined in the email attached as Exhibit A.

14 *Ibid*.

15 The email to the service list laying out the WG schedule is attached as Exhibit A.

workshop. These informal comments are attached as Exhibit B to this Report. Three parties (PG&E, CalCCA, and San Diego Gas & Electric Company (SDG&E)) expressed interest in presenting at the WG workshop. The co-leads facilitated the WG workshop by WebEx on July 27, 2020, beginning at 10:00 a.m. The co-leads jointly presented a review of the 7 Issues identified in D.20-06-002 and initial informal comments on the 7 Issues. Additionally, PG&E made a presentation as a participant in the WG to address pending issues. CalCCA also presented as a WG participant, offering two proposals. The only other party presenting a proposal was SDG&E. These presentations are attached as Exhibit C. WG participants submitted informal comments and replies regarding the WG workshop on August 3, 2020, attached as Exhibit D, and on August 17, 2020, attached as Exhibit E, respectively. A draft of the Report was circulated to WG participants on [August 21, 2020], with informal comments on the draft Report submitted on [August 26, 2020] and attached here as Exhibit F.

The workshop and parties' informal comments have helped inform this Report.

B. Topics Expressly Excluded from Scope

The Commission expressly identified certain topics as out-of-scope.[16] They include:

1. One-for-one credit mechanism for local RA that does not account for relative effectiveness of shown resources relative to bid resources;[17]

2. Ex-post price premium based on the average price paid by the CPE for resources in the local area for which a resource is shown;[18]

3. Credit mechanism for fossil fuel resources (other than potentially for existing contracts);[19] and

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16 D.20-06-002 at 43 ("The Commission is not open to considering a one-for-one credit, CalCCA's proposed financial credit mechanism, or a credit mechanism for fossil fuel resources (other than potentially for existing grandfathered contracts).").

17 *Id*. at 41.

18 *Id.* at 42.

19 *Id.* at 41.

4. An LCR RCM mechanism for the SDG&E Transmission Access Charge (TAC) area, where a CPE will not be designated.[20]

Stakeholders generally adhered to this guidance in offering proposals presented through the WG process and described in this Report.

C. Schedule of Completed Activities

The co-leads scheduled and completed the following WG activities:

Date	Activity	Status
July 6, 2020	Co-leads circulated notice to the service lists of WG co-leads and WG schedule, including workshop, and request for informal comments on 7 Issues outlined in D.20-06-002 on pages 43-45 and in Ordering Paragraphs 5 and 6.	Complete
July 17, 2020	Co-leads circulated notice of workshop date and call-in information to the service lists.	Complete
July 20, 2020	Parties submitted informal comments to the service lists in response to the co-leads' request on 7 Issues outlined in D.20-06-002 and notified co-leads of intent to present at workshop.	Complete
July 24, 2020	Co-leads circulated notice of agenda and presentation materials for the virtual workshop to service lists.	Complete
July 27, 2020	Co-leads hosted a virtual workshop on WebEx on LCR RCM and the treatment of existing contracts.	Complete
July 30, 2020	Co-leads again circulated presentations from virtual workshop to workshop participants, in addition to a matrix for parties to utilize in developing informal comments on the workshop.	Complete
July 31, 2020	Co-leads circulated updated schedule for WG to the service lists, including dates for informal reply comments on workshop, issuance of a draft Report, and informal comments on the draft Report.	Complete

20 *Id.* at Conclusion of Law 6.

August 3, 2020	Parties submitted informal comments on the workshop to co-leads, which were circulated to the service lists on August 4, 2020.	Complete
August 17, 2020	Parties submitted informal reply comments on the August 3 informal comments to the service lists (PG&E's informal reply comments were sent to the co-leads on August 17, 2020, and to the service lists on August 19, 2020).	Complete
August 20, 2020	Co-leads circulated an updated schedule for the WG to the service lists	Complete
August 21, 2020	Co-leads served a draft Report to the service lists for comment.	Complete
August 26, 2020	Parties submitted informal comments on the draft Report to the service lists.	[Complete]
September 1, 2020	Co-leads filed and served Report.	[Complete]

II. Guiding Principles and Objectives

The co-leads presented their views and interpretations on guiding principles and objectives in the July 27, 2020, workshop presentations.

A. Guidance from D.20-06-002

Drawing from D.20-06-002, the co-leads identified the following explicit guidance provided by the Commission, with the corresponding page number or ordering paragraph (OP) in brackets:

Effectiveness:

1. The LCR RCM cannot provide a "one for one" premium as CalCCA proposed without considering effectiveness. [p. 41]
2. The LCR RCM must address "local effectiveness" and "use limitations" of the shown resource to align the financial compensation with the actual LCR MW reduction the resource provided. [p. 42, OP 5]
3. The WG should consider how to adjust payments to an LSE "from year to year to account for changes in the effectiveness of the resource reducing local requirements." [OP 5.d.]

4. CPE selection criteria must include (1) "Local effectiveness factors, as published in the California Independent System Operator's Local Capacity Requirement Technical Studies" [OP 14.b.] and "Energy-use limitations" [OP 14.h.]

Least-Cost, Best-Fit:

a. "Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSE's seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE" [p. 42]
b. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]
c. "[E]nsures that ratepayers are: (1) only compensating resources to the extent they provide ratepayer value…" [p. 43]

Premium Determination and Market Power Issues:

1. The LCR RCM should "only compensate [] LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs" [p. 43]
2. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]
3. A "benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums" [p. 42]
4. "To the extent that market power inflates local area capacity prices, an ex post benchmark would exacerbate this problem by providing inflated prices to local resources shown by LSEs" [p. 42]
5. The WG must determine "[h]ow to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices." [OP 5.b]

Preferred Resource Development in Local Areas

1. "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas." [p. 41]

B. PG&E Proposed Principles

Based on the guidance in D.20-06-002, PG&E outlined the following four recommended principles for the LCR RCM in its workshop presentation included in Exhibit C:

- The LCR RCM should:

- Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;

- Reflect the effectiveness of a resource at meeting reliability requirements to prevent "leaning" by LSEs;

- Result in lower total costs to customers without sacrificing local area reliability; and

- Not be reflective of market power and/or introduce gaming opportunities but may reflect a "premium" based on the additional cost of developing resources in local areas.

WG participants also provided recommendations and comments on guiding principles.

The Alliance for Retail Energy Markets (AReM) proposed the following principles in the evaluation of the need and structure for any such compensation mechanism:

- No CPE Over-procurement - The ability for an LSE to receive an LCR RCM payment from the CPE must not result in over-procurement by the CPE with those costs spread among all LSEs;

- Cost Causation – Customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; costs should not be spread to other LSEs or their customers;

- Premiums Paid for Shown Resources Must Be Aligned with the Auction – LSEs with resources worth a premium to the CPE should be eligible for compensation up to that premium not more; and

- Payment Length for Show Resources Must Be Aligned with the Local RA Requirement – The number of years an LSE is eligible for an LCR RCM payment should not be longer than up to three years – the term of the Local RA requirement.

California Energy Storage Alliance (CESA), in addition to responses to the specific 7 Issues presented, also suggested that the WG should:

- consider pathways to maintain the load forecast adjustment process that is specific to an LSE and reflected in their pro rata share of the collective local RA requirements, and

- clarify and discuss the implications of the CPE buying all RA attributes if selected.

III. Description of Proposals

A. CalCCA Proposals

1. CalCCA Option #1

CalCCA's initial proposal, presented in its July 20, 2020, informal comments, advanced a CPE "must take" model. The model evolved as a result of the workshop and Parties' comments, however, into a refined "Option #1" proposal presented in CalCCA's July 27, 2020, comments. CalCCA does not recommend adoption of this approach but prefers its "Option #2" described below.

Under the must-take model, the CPE would be bound to take any local RA attributes from preferred or energy storage resources shown by an LSE. The price would be determined using the following formula:

> Year 1: Use the median price from the last four quarters of Energy Division Power Charge Indifference Adjustment (PCIA) responses for both system and local RA; subtract system RA price from local RA and multiply by effective megawatt (MW)
>
> Subsequent Years: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

This formulation removes the risk of market power influence by relying on the *median* CPE bid price rather than an *average* bid price. The median price is also unlikely to suggest pricing to future bidders, which an average price would do.

The number of MW shown by the LSE would be adjusted for effectiveness, using one of two methods. The first method would rely on published California Independent System Operator Corporation (CAISO) effectiveness factors, scaling a resource's effectiveness to the average effectiveness procured by the CPE in that specific local area. Because these factors do not fairly represent the value of resources, due to their focus on a limited subset of constraints, CalCCA

did not favor this approach. The second method would rely on a yet-to-be determined methodology using data regarding peak contribution of particular technologies in specific local areas and data underlying the CAISO's identified storage need in its annual Local Capacity Technical Study. CalCCA pointed out, however, that developing these technology-specific methodologies would be time consuming and would, at best, provide only rough justice in determining the showing value.

CalCCA does not support adoption of Option #1 due to the complexity of developing reasonable effectiveness calculations. In addition, it is difficult to square a CPE "must-take" model with the directive in D.20-06-002 that shown resources must be "evaluated alongside bid resources."

2. CalCCA Option #2

CalCCA advances its Option #2 as the preferred methodology for the LCR RCM. Unlike Option #1, the CPE would not be bound to accept all shown resources but could reject them after considering their value "alongside bid resources." The "pre-determined price" calculation would be the same as Option #1:

> <u>Year 1:</u> Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> <u>Subsequent Years:</u> Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

The only difference is that an LSE could choose to show its resources to the CPE for local credit at a price lower than the pre-determined price if desired.

The primary benefit of this approach, however, is administrative simplicity. Option #2 does not require further work to develop highly technical, technology-specific effectiveness

values. Instead, it relies on the guidelines the CPE will use to evaluate bid resources. In other words, the CPE would apply the same methodology or considerations to *bid* and *shown local RA* resources in comparing their value.

Beyond these fundamental features, CalCCA addressed term and documentation of showings. Resources committed through a showing would have a three-year commitment where the term start date could be any year within the three-year forward compliance period. The showing (like bid) would be documented through a confirm under the Edison Electric Institute (EEI) Master Agreement.

3. CalCCA Proposal on Treatment of Existing Contracts

In essence, since preferred and storage resources are covered by the showing option, the legacy treatment for existing contracts identified by D.20-06-002 LCR RCM would only apply to existing fossil <u>contracts</u>. The Commission did not extend this same authority for an investor owned utility (IOU) to show fossil utility owned generation (UOG). As stated in D.20-06-002, existing fossil UOG would be required to bid into the CPE solicitation, and bid UOG would receive Cost Allocation Mechanism (CAM) treatment.[21]

CalCCA proposes that existing fossil contracts receive legacy treatment for five years from the implementation of the CPE. Legacy contracts will include only resources that are currently online and were contracted by an LSE on or before June 11, 2020 (the date D.20-06-002 was issued).

Summary of CalCCA Option #2 LCR RCM Recommendation	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.

[21] D.20-06-002 at 48.

Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	If selected, LSE will be paid the showing price (pre-determined price or below) without annual adjustment for effectiveness, like bid resources.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose (see §b. above.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or lower if the LSE showed at a lower price) for the shown resource.
Premium Granularity	Price is differentiated by local area or sub-area, unless aggregation up is required to mask individual resource prices; not technology-specific prices.
Showing Term	LSE may show a resource for a term of up to three years, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show for the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing UOG "resources" do not qualify for a local showing.

B. SDG&E Proposal

SDG&E developed a proposal, included it in their July 20, 2020 comments, and presented the proposal at the July 27, 2020 workshop. SDG&E's proposal addressed local premium, effectiveness factors, duration, and cost-allocation.

On the local premium, SDG&E proposed that the CPE utilize the relevant Power Cost Indifference Adjustment (PCIA) System RA Market Price Benchmark (MPB) for its area, either NP-15 or SP-15 for the compliance year. SDG&E noted that the System RA MPB is typically available in November prior to the compliance year. SDG&E suggested consideration of the weighted average price of Local resources that were contracted by the CPE for the compliance year. This means that the CPE must identify the specific cost related to RA capacity procured if it procured other attributes, such as Flexible RA or energy tolling, which is necessary to ensure an apples-to-apples comparison. SDG&E also explored using the PCIA Local MPB, however it was unclear how the CPE procurement of Local resources would impact the PCIA Local MPB calculation. Therefore, SDG&E recommended using prices relevant to CPE procurement. SDG&E also maintained that both values could be made publicly available in November after the CPE has finished its procurement along with the publication of the annual PCIA MPBs.

On effectiveness, SDG&E argued that effectiveness factors should be guided by the CAISO and the annual Local Capacity Technical Study (LCTS). SDG&E proposed that the effectiveness factors for all shown resources be calculated based on the percentage resulting from the local or sub-area LCR divided by the total amount of capacity shown and CPE procured capacity. SDG&E provided the example that if the LCR is 100 MWs and 40 MWs were shown by LSEs, and 80 MWs were procured by the CPE, the percentage would be 100 MW / 120 MW, or 83.33 percent. LSEs that showed the total of 40 MWs would receive a credit of approximately 33.33 MWs.

In terms of duration, SDG&E proposed that the resources would be shown annually on a three-year rolling basis.

For cost-allocation, SDG&E proposed that the premium associated with the shown local RA capacity would reduce the costs allocated to the LSE by the CPE for the procurement.

C. PG&E Presentation and Proposals

While PG&E did not present a full proposal at the July 27, 2020 workshop, PG&E's presentation included proposed guiding principles for the LCR RCM, detailed above in Section II and repeated here for convenience:

- The LCR RCM should:
  - Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;
  - Reflect the effectiveness of a resource at meeting reliability requirements to prevent "leaning" by LSEs;
  - Result in lower total costs to customers without sacrificing local area reliability; and
  - Not be reflective of market power and/or introduce gaming opportunities but may reflect a "premium" based on the additional cost of developing resources in local areas.

PG&E's presentation explained that PG&E had not identified a mechanism for developing a price that clearly met these proposed guiding principles. In attempting to establish an appropriate local price, PG&E considered two options: cost-based and market-based. PG&E discussed how each of these prices could be derived and outlined the drawbacks of each option. PG&E also proposed that the LCR RCM premium should be as granular as possible in order to send the correct market signals.

PG&E further explained its view that any "workable" solution must be paired with a transparent and appropriate effectiveness adjustment and demonstration of reduction in total costs to customers. PG&E's presentation provided information regarding the complexity and potential infeasibility of developing effectiveness adjustments using CAISO effectiveness factors, as well as other measures of effectiveness that could be explored.

PG&E concluded its presentation by stating that the LCR RCM should not result in an increase in total costs to customers. In other words, resources paid through this mechanism must be lower cost than its alternative, and the mechanism must not be game-able.

In addition, PG&E utilized the July 20, 2020, informal comments to provide its proposals with respect to treatment of existing contracts and existing owned resources. First, PG&E

proposed that legacy treatment of existing contracts not be afforded to contracts for local resources that were procured outside of an LSE's transmission access charge (TAC) area (e.g. a northern California LSE that procured a resource within a southern California LSE's TAC), as those resources were not procured by the LSE to meet local RA requirements, but were likely procured to meet the LSE's system RA requirements. PG&E also proposed that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired, prior to the date of issuance of D.19-02-022, March 4, 2019 (i.e. when the Commission affirmed its intent to adopt a centralized procurement framework for local RA resources and the possibility that LSEs may no longer have a procurement obligation for local RA). PG&E also proposed that legacy treatment not be applied for the full term of an existing contract or the life of an existing owned resource.

IV. Consensus and Non-Consensus Items

A. Matrix of party positions

As part of the WG process, the co-leads developed a matrix of party positions that covers key questions, including effectiveness, granularity, transparency, bidding issues, annual adjustments, the evaluation process, and shows where there is consensus and non-consensus among parties. The matrix was distributed to workshop participants on July 30, 2020, and parties provided edits to the matrix as part of informal comments submitted on August 3, 2020. The matrix has been updated to incorporate edits submitted on August 3, 2020, and is included in this Report as Exhibit G.

B. Summary of Consensus and Non-Consensus Items for the 7 Issues

1. Cost-effectiveness

While some parties stated that the mechanism should not provide compensation if the resource does not provide value (CalPA) or does not reduce costs (PG&E), other parties argued that cost-effectiveness should not be in scope (CEDMC). Others raised feasibility of the mechanism if CAISO would need to provide information on effectiveness (SCE, SDG&E). Others argued that the CPE should produce multiple portfolios, akin to the transmission alternative portfolios the CAISO creates in the Transmission Planning Process, as a means to address cost-effectiveness (CESA).

With respect to how the mechanism should address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources, six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the topic should be within the scope of the mechanism and one party (CEDMC) stated that it should be outside of the scope of the mechanism.

PG&E and CESA expressed that a resource should demonstrate its effectiveness to receive compensation. CESA looks to have the assessment incorporate non-quantitative criteria, whereas PG&E looks to have only quantitative criteria used.

Six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the effectiveness adjustments could be determined by the CAISO through various mechanisms. The specific actions suggested by the parties varied, ranging from: adjustments to NQC values (PG&E), determination of effectiveness factors (SCE), using the Local Capacity Technical Study (SDG&E), and developing a stakeholder process for determining the appropriate mechanism (CalCCA).

CalCCA's final proposal (Option #2) left the question to the CPE. The CPE is required to take effectiveness into account in selecting bids from its solicitations. Since CalCCA's proposal (Option #2) contemplates a comparison of shown preferred resources alongside bid resources, CalCCA submits that the CPE should apply the same criteria – whatever they may be – to both bid and shown resources.

2. Premium granularity

There was a broad spectrum of perspectives on premium granularity. Some parties argued that the premium should be dependent on the data available; for example, it could be sub-area, local area, or TAC-wide area (SCE). Others argued for premiums for each resource technology type (CalPA) or by resource type, location, or operational characteristics (CEDMC), or based on location, including disadvantaged communities (DACs), GHG emissions reduction, and market power mitigation (CESA).

With respect to how granular the premium should be, three parties stated that the price premiums should be differentiated by local areas or sub-local areas (CalCCA, PG&E, and SDG&E) and one party stated that it should be differentiated by the TAC-wide area (SCE) unless a higher level of aggregation was required to mask the price of individual resource prices. SDG&E stated that the complexity of developing individual premiums for the various types of resources makes the task infeasible.

One party stated that a series of premiums should be stacked to arrive at the final premium for a resource (e.g., closer-to-load, within a DAC, GHG emission reduction, and offers market power mitigation) (CESA). An additional party referenced a premium for a resource being located within a DAC (CEDMC).

3. Transparency of premium

Parties broadly supported as much transparency as possible, while still protecting market-sensitive information. Parties presented numerous ideas on how and when data should be presented. For instance, PG&E advocated for aggregating data upfront and making more detailed data available after sufficient time had passed. CalPA argued for posting the premiums to the service list and CESA argued that premiums should be made available by resource class. SDG&E argued that advance knowledge of the premium is not necessary since LSEs could still show the resource if the offer is not selected by the CPE.

CalCCA observed that its proposal would allow for full transparency of the predetermined price. Neither source of data required for the calculation -- the median bid price from the last CPE solicitation and the aggregated RA prices reported to Energy Division -- presents concerns regarding market sensitivity. The Energy Division prices are made public annually, and the median CPE price would reveal very little about the stratification of bids actually accepted by the CPE.

4. Bidding issues

On the issue of whether the mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation, both PG&E and CalCCA argued that the LSE would need to choose between voluntarily showing (for mechanism eligibility) and bidding / showing as part of the solicitation process. CESA argued that the LSE should not be precluded from also bidding and showing. SCE recommended that this topic be further discussed in workshops to address issues of gaming risk.

CalCCA also proposes a price formula for the pre-determined price. The "pre-determined price" calculation would be calculated as follows:

> <u>Year 1:</u> Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> <u>Subsequent Years:</u> Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results

(prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

An LSE could choose to show its preferred or energy storage resources to the CPE for local credit at a price lower than the pre-determined price if desired.

5. Annual adjustments to local compensation

Parties had differing views on how frequently the mechanism should be adjusted. PG&E advocated that the premium should be updated annually to reflect the most recent CAISO Local Capacity Technical Study Report. CESA argued that an annual adjustment would not be necessary. Others argued that annual adjustments would ultimately depend on the details of the mechanism (SCE).

Because CalCCA proposes comparison of the shown resource alongside bid resources, as D.20-06-002 requires, CalCCA proposes no annual adjustment to the compensation. Bid resources are not adjusted annually for effectiveness but are paid as bid. In the same way, shown resources should be paid for the term of the showing at the pre-determined price (or below).

6. Bid evaluation process

On the question of how the CPE should incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources, there were several disparate ideas. SCE argued that the question should be addressed in CPE implementation as it relates to the bid selection process and bid selection criteria and how the CPE will fairly implement the least-cost-best-fit procurement criteria. CEDMC argued that both qualitative and quantitative criteria be considered, and preferred resources should be favored over fossil-fueled resources. CESA argued that the criteria should link to integrated-resource-plan-identified future long-term procurement needs in local or sub-local areas and adhere to the loading order and SB 1136 statutory requirements to facilitate the development of preferred, energy storage, and hybrid resources to the greatest extent possible.

7. Treatment of existing contracts

There were several proposals relating to the treatment of existing contracts that spanned a cutoff date for qualification, the period over which a contract should qualify, and whether UOG should qualify.

On the issue of a cutoff date, PG&E and SCE advocated that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired prior to the date of issuance of D.19-02-022, March 4, 2019. CalCCA argued that the mechanism should be applied to existing contracts entered into by an LSE on or before June 11, 2020.

On the issue of the period over which a contract should qualify, SCE argued that it should be for up to a five-year term length. PG&E also stated that legacy treatment should not apply for the full term of the existing contract or owned resource. CalCCA recommends that the term be consistent with the terms sought for bid resources.

Lastly, on the issue of UOG, CalCCA argued that UOG should not be eligible, while PG&E advocated for eligibility for UOG.

V. Consensus and Non-Consensus Around Full LCR RCM Proposals

A. CalCCA's Proposal (Option #2)

CalCCA offered a complete proposal (Option #2) for the LCR RCM, summarized in their comments as follows:

Shown Resources Compared Alongside Bid Resources	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	No annual adjustment for effectiveness.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or the LSE's lower shown price) for the local RA premium.
Premium Granularity	Local area or sub-area unless aggregation up is required to mask individual resource prices; no technology differentiation in pre-determined price.
Showing Term	LSE may show a resource for whatever term the CPE permits for its solicitations, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show its local RA attributes and receive the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing owned fossil resources do not qualify for a local showing.

Several parties expressed interest in this proposal, although there was not broad consensus reached from all parties involved in the WG. Both Calpine Corporation and AReM submitted informal comments questioning the concept of permitting bids outside of the auction process and suggesting that there should be "full flexibility to specify the prices at which shown resources will be compared to bid resources" in the CPE's auction to provide LSEs "incentives to offer competitively to ensure that their resources are selected over offered resources." AReM observed that all options for a compensation mechanism have risks for market power and gaming

and questioned "if the limited potential benefits warrant moving forward with any compensation mechanism."

PG&E submitted comments in reply to CalCCA's proposal (Option #2) stating that PG&E did not find that the proposal clearly meets all of the objectives in D.20-06-002; however, PG&E believes it is reasonable and the only workable solution that has been put forth by the WG that clearly meets the objective of allowing LSEs to retain the system and flexible RA attributes and receive compensation for the local RA attribute under the hybrid procurement framework. If the Commission is willing to consider this proposal, PG&E believes that (i) all LSEs, including IOUs, should be able to avail themselves of the LCR RCM in the same manner (which requires the Commission to revisit IOU bidding requirements in D.20-06-002 in a new track of the RA proceeding or identify another venue to evaluate the bidding requirements for IOUs to participate in the LCR RCM proposed by CalCCA in Option #2), and (ii) LSEs should continue to be afforded the "voluntarily shown" option, without compensation under the LCR RCM, should LSEs want to retain the system/flexible RA products for use toward its LSE-specific system and flexible RA requirements.

SCE also submitted comments in reply to CalCCA's proposal (Option #2) stating that there are merits to the proposal, and it should be further explored. SCE recommended a few clarifications to the proposal, including (i) if a shown resource is selected by the CPE during the solicitation, then the LSE should be paid its offer price for the shown resource, not the pre-determined premium, and (ii) the option of showing a local resource without direct compensation should be retained and made available to all LSEs.

B. SDG&E's Proposal

As described in Section III.B, SDG&E also provided a full proposal on the LCR RCM. PG&E submitted comments on SDG&E's proposal expressing concerns that the proposed methodology does not appropriately addresses cost effectiveness concerns. PG&E believes that it may overestimate voluntarily shown resources, which may result in customers paying for resources that do not provide any ratepayer value or any local area reliability benefits to the system. Additionally, PG&E has concerns with SDG&E's proposal on local premium price, as this methodology is similar to the financial crediting mechanism proposed by CalCCA in Rulemaking 17-09-020 that was rejected by the Commission and specifically excluded from the scope of consideration in this Track.

Exhibits

Exhibit A: July 6, 2020 Service Email

Exhibit B: July 20, 2020 Informal Comments

Exhibit C: July 27, 2020 WG Workshop Presentations

Exhibit D: August 3, 2020 Informal Comments

Exhibit E: August 17, 2020 Informal Reply Comments

Exhibit F: August 26, 2020 Informal Comments on Draft Report

Exhibit G: Final Matrix of Party Positions

Subject:	R.17-09-020_RA OIR & R.19-11-009: SCE Proposed Revisions to (DRAFT) Co-Leads Working Group Report on LCR RCM and Treatment of Existing Contracts
Date:	Wednesday, August 26, 2020 at 3:17:20 PM Pacific Daylight Time
From:	Legal.Admin@sce.com
To:	s.tougas@CleanEnergyRegResearch.com
Attachments:	SCE Proposed Revisions to (DRAFT) Co-Leads Working Group Report on LCR RCM and Treatment of Existing Contracts.docx, R1709020_Servist List.pdf, R1911009_Service List.pdf

To the Working Group Co-Leads and all parties in R.17-09-020 and R.19-11-009:

As requested in your e-mail of August 21, 2020, attached is Southern California Edison Company's Proposed Revisions to (DRAFT) Co-Leads Working Group Report on LCR RCM and Treatment of Existing Contracts. This document is hereby served by electronic mail upon all parties listed in the official service lists for R.17-09-020 and R.19-11-009.

(See attached file: SCE Proposed Revisions to (DRAFT) Co-Leads Working Group Report on LCR RCM and Treatment of Existing Contracts.docx)

(See attached file: R1709020_Servist List.pdf)

(See attached file: R1911009_Service List.pdf)

Regards,

Legal Administration
Southern California Edison Company
Telephone: (626) 302-6950
Email: Legal.Admin@sce.com

ATTACHMENT 1 TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) TRACK 3.A WORKING GROUP REPORT ON CONSENSUS AND NON-CONSENSUS ITEMS REGARDING DEVELOPMENT OF LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND PROPOSAL ON TREATMENT OF EXISTING CONTRACTS

WORKING GROUP REPORT

[TABLE OF CONTENTS TO BE INSERTED]

Working Group Report on Consensus and Non-Consensus Items Regarding Development of Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Proposal on Treatment of Existing Contracts

I. Background

A. Procedural Background and Scope

Decision (D.) 20-06-002 adopts implementation details for the central procurement of multi-year local resource adequacy (RA) to begin for the 2023 compliance year in the Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) distribution service areas, including identifying PG&E and SCE as the central procurement entities (CPE) for their respective distribution service areas and adopting a hybrid central procurement framework.[1] The framework places full local RA procurement responsibility on behalf of all load serving entities (LSE) on the CPE, and LSEs no longer receive individual local requirements.[2] LSEs that have procured local resources may "(1) show the resource to reduce the central procurement entity's (CPE) overall local procurement obligation and retain 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."[3] Under the "show" option, the LSE does not receive one-for-one credit for its local resources.[4]

In adopting the hybrid central procurement framework, the California Public Utilities Commission (Commission) found that, even without a financial crediting mechanism, the framework does not disincentivize procurement of local resources because LSEs procure local

[1] D.20-06-002 at 1, Ordering Paragraphs 2-4.
[2] *Id*. at 22-23, Ordering Paragraph 3.
[3] *Id*. at 23, Ordering Paragraph 4.
[4] *Id*. at 23.

resources for many reasons beyond the local RA value.[5] The Commission recognized, however, that "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas."[6] To that end, the Commission committed to developing a "financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value" (LCR RCM), if details can be assessed and developed.[7] To develop such a mechanism, the Commission directed a working group (WG) co-led by CalCCA and either PG&E or SCE.[8] The Commission also included within the scope of the WG issues related to treatment of existing contracts, including potential application of the LCR RCM to these contracts.[9] The Commission further required the co-leads to file a WG report on consensus and non-consensus items (Report) in this proceeding by September 1, 2020. In addition, the assigned Commissioner in this proceeding issued the *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling*, dated July 7, 2020 (Amended Scoping Memo), designating evaluation of an LCR RCM as an issue in Track 3.A and requiring WG reports and proposals from parties to be filed on September 1, 2020.

In both D.20-06-002 and the Amended Scoping Memo, the Commission identified four specific issues to be addressed by the Report:[10]

a. How granular the premium should be (*e.g.*, should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);

b. How to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

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5 *Id*. at 40-41, 72.
6 *Id*. at 42, 72.
7 *Id*., at 43.
8 *Id*. at Ordering Paragraph 5.
9 *Id*. at 46, 75 and Ordering Paragraph 6.
10 *Id*. at Ordering Paragraph 5.

c. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process; and

d. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

In addition, the Commission directed in D.20-06-002 that the Report "address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources."[11] D.20-06-002 also requires the WG to (i) "consider and submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing contracts"[12] and (ii) consider how the CPE will incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small."[13] The Report must also address consensus and non-consensus items regarding treatment of existing contracts.[14]

Using this guidance, CalCCA and PG&E, serving as WG co-leads, sent an email to the service list on July 6, 2020, soliciting initial input from stakeholders through informal comments submitted on July 20, 2020, and seeking participation by other stakeholders with an interest in presenting at a WG workshop on the identified issues set for July 27, 2020.[15] Eight parties submitted informal comments on the 7 Issues on July 20, 2020 ahead of the July 27, 2020 WG

[11] *Id.* at Ordering Paragraph 5. The Amended Scoping Memo includes a similar requirement. Amended Scoping Memo at 3.

[12] *Id.* at Ordering Paragraph 6.

[13] *Id*. at pp. 44-45. The four issues identified above (a.-d.) and the three issues identified in this paragraph (i.e. in the first sentence and romanettes (i) and (ii) of the second sentence) are referred to herein as the "7 Issues." The 7 Issues are also outlined in the email attached as Exhibit A.

[14] *Ibid*.

[15] The email to the service list laying out the WG schedule is attached as Exhibit A.

workshop. These informal comments are attached as Exhibit B to this Report. Three parties (PG&E, CalCCA, and San Diego Gas & Electric Company (SDG&E)) expressed interest in presenting at the WG workshop. The co-leads facilitated the WG workshop by WebEx on July 27, 2020, beginning at 10:00 a.m. The co-leads jointly presented a review of the 7 Issues identified in D.20-06-002 and initial informal comments on the 7 Issues. Additionally, PG&E made a presentation as a participant in the WG to address pending issues. CalCCA also presented as a WG participant, offering two proposals. The only other party presenting a proposal was SDG&E. These presentations are attached as Exhibit C. WG participants submitted informal comments and replies regarding the WG workshop on August 3, 2020, attached as Exhibit D, and on August 17, 2020, attached as Exhibit E, respectively. A draft of the Report was circulated to WG participants on [August 21, 2020], with informal comments on the draft Report submitted on [August 26, 2020] and attached here as Exhibit F.

The workshop and parties' informal comments have helped inform this Report.

B. Topics Expressly Excluded from Scope

The Commission expressly identified certain topics as out-of-scope.[16] They include:

1. One-for-one credit mechanism for local RA that does not account for relative effectiveness of shown resources relative to bid resources;[17]

2. Ex-post price premium based on the average price paid by the CPE for resources in the local area for which a resource is shown;[18]

3. Credit mechanism for fossil fuel resources (other than potentially for existing contracts);[19] and

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[16] D.20-06-002 at 43 ("The Commission is not open to considering a one-for-one credit, CalCCA's proposed financial credit mechanism, or a credit mechanism for fossil fuel resources (other than potentially for existing grandfathered contracts).").

[17] *Id*. at 41.

[18] *Id.* at 42.

[19] *Id.* at 41.

4. An LCR RCM mechanism for the SDG&E Transmission Access Charge (TAC) area, where a CPE will not be designated.[20]

Stakeholders generally adhered to this guidance in offering proposals presented through the WG process and described in this Report.

C. Schedule of Completed Activities

The co-leads scheduled and completed the following WG activities:

Date	Activity	Status
July 6, 2020	Co-leads circulated notice to the service lists of WG co-leads and WG schedule, including workshop, and request for informal comments on 7 Issues outlined in D.20-06-002 on pages 43-45 and in Ordering Paragraphs 5 and 6.	Complete
July 17, 2020	Co-leads circulated notice of workshop date and call-in information to the service lists.	Complete
July 20, 2020	Parties submitted informal comments to the service lists in response to the co-leads' request on 7 Issues outlined in D.20-06-002 and notified co-leads of intent to present at workshop.	Complete
July 24, 2020	Co-leads circulated notice of agenda and presentation materials for the virtual workshop to service lists.	Complete
July 27, 2020	Co-leads hosted a virtual workshop on WebEx on LCR RCM and the treatment of existing contracts.	Complete
July 30, 2020	Co-leads again circulated presentations from virtual workshop to workshop participants, in addition to a matrix for parties to utilize in developing informal comments on the workshop.	Complete
July 31, 2020	Co-leads circulated updated schedule for WG to the service lists, including dates for informal reply comments on workshop, issuance of a draft Report, and informal comments on the draft Report.	Complete

[20] *Id.* at Conclusion of Law 6.

August 3, 2020	Parties submitted informal comments on the workshop to co-leads, which were circulated to the service lists on August 4, 2020.	Complete
August 17, 2020	Parties submitted informal reply comments on the August 3 informal comments to the service lists (PG&E's informal reply comments were sent to the co-leads on August 17, 2020, and to the service lists on August 19, 2020).	Complete
August 20, 2020	Co-leads circulated an updated schedule for the WG to the service lists	Complete
August 21, 2020	Co-leads served a draft Report to the service lists for comment.	Complete
August 26, 2020	Parties submitted informal comments on the draft Report to the service lists.	[Complete]
September 1, 2020	Co-leads filed and served Report.	[Complete]

II. Guiding Principles and Objectives

The co-leads presented their views and interpretations on guiding principles and objectives in the July 27, 2020, workshop presentations.

A. Guidance from D.20-06-002

Drawing from D.20-06-002, the co-leads identified the following explicit guidance provided by the Commission, with the corresponding page number or ordering paragraph (OP) in brackets:

<u>Effectiveness:</u>

1. The LCR RCM cannot provide a "one for one" premium as CalCCA proposed without considering effectiveness. [p. 41]
2. The LCR RCM must address "local effectiveness" and "use limitations" of the shown resource to align the financial compensation with the actual LCR MW reduction the resource provided. [p. 42, OP 5]
3. The WG should consider how to adjust payments to an LSE "from year to year to account for changes in the effectiveness of the resource reducing local requirements." [OP 5.d.]

4. CPE selection criteria must include (1) "Local effectiveness factors, as published in the California Independent System Operator's Local Capacity Requirement Technical Studies" [OP 14.b.] and "Energy-use limitations" [OP 14.h.]

Least-Cost, Best-Fit:

a. "Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSE's seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE" [p. 42]
b. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]
c. "[E]nsures that ratepayers are: (1) only compensating resources to the extent they provide ratepayer value…" [p. 43]

Premium Determination and Market Power Issues:

1. The LCR RCM should "only compensate [] LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs" [p. 43]
2. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]
3. A "benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums" [p. 42]
4. "To the extent that market power inflates local area capacity prices, an ex post benchmark would exacerbate this problem by providing inflated prices to local resources shown by LSEs" [p. 42]
5. The WG must determine "[h]ow to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices." [OP 5.b]

Preferred Resource Development in Local Areas

1. "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas." [p. 41]

B. PG&E Proposed Principles

Based on the guidance in D.20-06-002, PG&E outlined the following four recommended principles for the LCR RCM in its workshop presentation included in Exhibit C:

- The LCR RCM should:

- Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;
- Reflect the effectiveness of a resource at meeting reliability requirements to prevent "leaning" by LSEs;
- Result in lower total costs to customers without sacrificing local area reliability; and
- Not be reflective of market power and/or introduce gaming opportunities but may reflect a "premium" based on the additional cost of developing resources in local areas.

WG participants also provided recommendations and comments on guiding principles.

The Alliance for Retail Energy Markets (AReM) proposed the following principles in the evaluation of the need and structure for any such compensation mechanism:

- No CPE Over-procurement - The ability for an LSE to receive an LCR RCM payment from the CPE must not result in over-procurement by the CPE with those costs spread among all LSEs;
- Cost Causation – Customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; costs should not be spread to other LSEs or their customers;
- Premiums Paid for Shown Resources Must Be Aligned with the Auction – LSEs with resources worth a premium to the CPE should be eligible for compensation up to that premium not more; and
- Payment Length for Show Resources Must Be Aligned with the Local RA Requirement – The number of years an LSE is eligible for an LCR RCM payment should not be longer than up to three years – the term of the Local RA requirement.

California Energy Storage Alliance (CESA), in addition to responses to the specific 7 Issues presented, also suggested that the WG should:

- consider pathways to maintain the load forecast adjustment process that is specific to an LSE and reflected in their pro rata share of the collective local RA requirements, and
- clarify and discuss the implications of the CPE buying all RA attributes if selected.

III. Description of Proposals

A. CalCCA Proposals

1. CalCCA Option #1

CalCCA's initial proposal, presented in its July 20, 2020, informal comments, advanced a CPE "must take" model. The model evolved as a result of the workshop and Parties' comments, however, into a refined "Option #1" proposal presented in CalCCA's July 27, 2020, comments. CalCCA does not recommend adoption of this approach but prefers its "Option #2" described below.

Under the must-take model, the CPE would be bound to take any local RA attributes from preferred or energy storage resources shown by an LSE. The price would be determined using the following formula:

> <u>Year 1:</u> Use the median price from the last four quarters of Energy Division Power Charge Indifference Adjustment (PCIA) responses for both system and local RA; subtract system RA price from local RA and multiply by effective megawatt (MW)
>
> <u>Subsequent Years:</u> Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

This formulation removes the risk of market power influence by relying on the *median* CPE bid price rather than an *average* bid price. The median price is also unlikely to suggest pricing to future bidders, which an average price would do.

The number of MW shown by the LSE would be adjusted for effectiveness, using one of two methods. The first method would rely on published California Independent System Operator Corporation (CAISO) effectiveness factors, scaling a resource's effectiveness to the average effectiveness procured by the CPE in that specific local area. Because these factors do not fairly represent the value of resources, due to their focus on a limited subset of constraints, CalCCA

did not favor this approach. The second method would rely on a yet-to-be determined methodology using data regarding peak contribution of particular technologies in specific local areas and data underlying the CAISO's identified storage need in its annual Local Capacity Technical Study. CalCCA pointed out, however, that developing these technology-specific methodologies would be time consuming and would, at best, provide only rough justice in determining the showing value.

CalCCA does not support adoption of Option #1 due to the complexity of developing reasonable effectiveness calculations. In addition, it is difficult to square a CPE "must-take" model with the directive in D.20-06-002 that shown resources must be "evaluated alongside bid resources."

2. CalCCA Option #2

CalCCA advances its Option #2 as the preferred methodology for the LCR RCM. Unlike Option #1, the CPE would not be bound to accept all shown resources but could reject them after considering their value "alongside bid resources." The "pre-determined price" calculation would be the same as Option #1:

> Year 1: Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> Subsequent Years: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

The only difference is that an LSE could choose to show its resources to the CPE for local credit at a price lower than the pre-determined price if desired.

The primary benefit of this approach, however, is administrative simplicity. Option #2 does not require further work to develop highly technical, technology-specific effectiveness

values. Instead, it relies on the guidelines the CPE will use to evaluate bid resources. In other words, the CPE would apply the same methodology or considerations to *bid* and *shown local RA* resources in comparing their value.

Beyond these fundamental features, CalCCA addressed term and documentation of showings. Resources committed through a showing would have a three-year commitment where the term start date could be any year within the three-year forward compliance period. The showing (like bid) would be documented through a confirm under the Edison Electric Institute (EEI) Master Agreement.

3. CalCCA Proposal on Treatment of Existing Contracts

In essence, since preferred and storage resources are covered by the showing option, the legacy treatment for existing contracts identified by D.20-06-002 LCR RCM would only apply to existing fossil contracts. The Commission did not extend this same authority for an investor owned utility (IOU) to show fossil utility owned generation (UOG). As stated in D.20-06-002, existing fossil UOG would be required to bid into the CPE solicitation, and bid UOG would receive Cost Allocation Mechanism (CAM) treatment.[21]

CalCCA proposes that existing fossil contracts receive legacy treatment for five years from the implementation of the CPE. Legacy contracts will include only resources that are currently online and were contracted by an LSE on or before June 11, 2020 (the date D.20-06-002 was issued).

Summary of CalCCA Option #2 LCR RCM Recommendation	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.

[21] D.20-06-002 at 48.

Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	If selected, LSE will be paid the showing price (pre-determined price or below) without annual adjustment for effectiveness, like bid resources.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose (see §b. above.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or lower if the LSE showed at a lower price) for the shown resource.
Premium Granularity	Price is differentiated by local area or sub-area, unless aggregation up is required to mask individual resource prices; not technology-specific prices.
Showing Term	LSE may show a resource for a term of up to three years, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show for the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing UOG "resources" do not qualify for a local showing.

B. SDG&E Proposal

SDG&E developed a proposal, included it in their July 20, 2020 comments, and presented the proposal at the July 27, 2020 workshop. SDG&E's proposal addressed local premium, effectiveness factors, duration, and cost-allocation.

On the local premium, SDG&E proposed that the CPE utilize the relevant Power Cost Indifference Adjustment (PCIA) System RA Market Price Benchmark (MPB) for its area, either NP-15 or SP-15 for the compliance year. SDG&E noted that the System RA MPB is typically available in November prior to the compliance year. SDG&E suggested consideration of the weighted average price of Local resources that were contracted by the CPE for the compliance year. This means that the CPE must identify the specific cost related to RA capacity procured if it procured other attributes, such as Flexible RA or energy tolling, which is necessary to ensure an apples-to-apples comparison. SDG&E also explored using the PCIA Local MPB, however it was unclear how the CPE procurement of Local resources would impact the PCIA Local MPB calculation. Therefore, SDG&E recommended using prices relevant to CPE procurement. SDG&E also maintained that both values could be made publicly available in November after the CPE has finished its procurement along with the publication of the annual PCIA MPBs.

On effectiveness, SDG&E argued that effectiveness factors should be guided by the CAISO and the annual Local Capacity Technical Study (LCTS). SDG&E proposed that the effectiveness factors for all shown resources be calculated based on the percentage resulting from the local or sub-area LCR divided by the total amount of capacity shown and CPE procured capacity. SDG&E provided the example that if the LCR is 100 MWs and 40 MWs were shown by LSEs, and 80 MWs were procured by the CPE, the percentage would be 100 MW / 120 MW, or 83.33 percent. LSEs that showed the total of 40 MWs would receive a credit of approximately 33.33 MWs.

In terms of duration, SDG&E proposed that the resources would be shown annually on a three-year rolling basis.

For cost-allocation, SDG&E proposed that the premium associated with the shown local RA capacity would reduce the costs allocated to the LSE by the CPE for the procurement.

C. PG&E Presentation and Proposals

While PG&E did not present a full proposal at the July 27, 2020 workshop, PG&E's presentation included proposed guiding principles for the LCR RCM, detailed above in Section II and repeated here for convenience:

- The LCR RCM should:
    - o Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;
    - o Reflect the effectiveness of a resource at meeting reliability requirements to prevent "leaning" by LSEs;
    - o Result in lower total costs to customers without sacrificing local area reliability; and
    - o Not be reflective of market power and/or introduce gaming opportunities but may reflect a "premium" based on the additional cost of developing resources in local areas.

PG&E's presentation explained that PG&E had not identified a mechanism for developing a price that clearly met these proposed guiding principles. In attempting to establish an appropriate local price, PG&E considered two options: cost-based and market-based. PG&E discussed how each of these prices could be derived and outlined the drawbacks of each option. PG&E also proposed that the LCR RCM premium should be as granular as possible in order to send the correct market signals.

PG&E further explained its view that any "workable" solution must be paired with a transparent and appropriate effectiveness adjustment and demonstration of reduction in total costs to customers. PG&E's presentation provided information regarding the complexity and potential infeasibility of developing effectiveness adjustments using CAISO effectiveness factors, as well as other measures of effectiveness that could be explored.

PG&E concluded its presentation by stating that the LCR RCM should not result in an increase in total costs to customers. In other words, resources paid through this mechanism must be lower cost than its alternative, and the mechanism must not be game-able.

In addition, PG&E utilized the July 20, 2020, informal comments to provide its proposals with respect to treatment of existing contracts and existing owned resources. First, PG&E

proposed that legacy treatment of existing contracts not be afforded to contracts for local resources that were procured outside of an LSE's transmission access charge (TAC) area (e.g. a northern California LSE that procured a resource within a southern California LSE's TAC), as those resources were not procured by the LSE to meet local RA requirements, but were likely procured to meet the LSE's system RA requirements. PG&E also proposed that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired, prior to the date of issuance of D.19-02-022, March 4, 2019 (i.e. when the Commission affirmed its intent to adopt a centralized procurement framework for local RA resources and the possibility that LSEs may no longer have a procurement obligation for local RA). PG&E also proposed that legacy treatment not be applied for the full term of an existing contract or the life of an existing owned resource.

IV. Consensus and Non-Consensus Items

A. Matrix of party positions

As part of the WG process, the co-leads developed a matrix of party positions that covers key questions, including effectiveness, granularity, transparency, bidding issues, annual adjustments, the evaluation process, and shows where there is consensus and non-consensus among parties. The matrix was distributed to workshop participants on July 30, 2020, and parties provided edits to the matrix as part of informal comments submitted on August 3, 2020. The matrix has been updated to incorporate edits submitted on August 3, 2020, and is included in this Report as Exhibit G.

B. Summary of Consensus and Non-Consensus Items for the 7 Issues

1. Cost-effectiveness

While some parties stated that the mechanism should not provide compensation if the resource does not provide value (CalPA) or does not reduce costs (PG&E), other parties argued that cost-effectiveness should not be in scope (CEDMC). Others raised feasibility of the mechanism if CAISO would need to provide information on effectiveness (SCE, SDG&E). Others argued that the CPE should produce multiple portfolios, akin to the transmission alternative portfolios the CAISO creates in the Transmission Planning Process, as a means to address cost-effectiveness (CESA).

With respect to how the mechanism should address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources, six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the topic should be within the scope of the mechanism and one party (CEDMC) stated that it should be outside of the scope of the mechanism.

PG&E and CESA expressed that a resource should demonstrate its effectiveness to receive compensation. CESA looks to have the assessment incorporate non-quantitative criteria, whereas PG&E looks to have only quantitative criteria used.

Six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the effectiveness adjustments could be determined by the CAISO through various mechanisms. The specific actions suggested by the parties varied, ranging from: adjustments to NQC values (PG&E), determination of effectiveness ~~factors~~ based on the portfolio options of the CPE (SCE), using the Local Capacity Technical Study (SDG&E), and developing a stakeholder process for determining the appropriate mechanism (CalCCA).

CalCCA's final proposal (Option #2) left the question to the CPE. The CPE is required to take effectiveness into account in selecting bids from its solicitations. Since CalCCA's proposal (Option #2) contemplates a comparison of shown preferred resources alongside bid resources, CalCCA submits that the CPE should apply the same criteria – whatever they may be – to both bid and shown resources.

2. Premium granularity

There was a broad spectrum of perspectives on premium granularity. Some parties argued that the premium should be dependent on the data available; for example, it could be sub-area, local area, or TAC-wide area (SCE). Others argued for premiums for each resource technology type (CalPA) or by resource type, location, or operational characteristics (CEDMC), or based on location, including disadvantaged communities (DACs), GHG emissions reduction, and market power mitigation (CESA).

With respect to how granular the premium should be, three parties stated that the price premiums should be differentiated by local areas or sub-local areas (CalCCA, PG&E, and SDG&E) ~~and one party stated that it should be differentiated by the TAC-wide area (SCE)~~ [Note: Although SCE mentioned this as a possible option, it was not proposing differentiation by the TAC wide area.] unless a higher level of aggregation was required to mask the price of individual resource prices. SDG&E stated that the complexity of developing individual premiums for the various types of resources makes the task infeasible.

One party stated that a series of premiums should be stacked to arrive at the final premium for a resource (e.g., closer-to-load, within a DAC, GHG emission reduction, and offers market power mitigation) (CESA). An additional party referenced a premium for a resource being located within a DAC (CEDMC).

3. Transparency of premium

Parties broadly supported as much transparency as possible, while still protecting market-sensitive information. Parties presented numerous ideas on how and when data should be presented. For instance, PG&E advocated for aggregating data upfront and making more detailed data available after sufficient time had passed. CalPA argued for posting the premiums to the service list and CESA argued that premiums should be made available by resource class. SDG&E argued that advance knowledge of the premium is not necessary since LSEs could still show the resource if the offer is not selected by the CPE.

CalCCA observed that its proposal would allow for full transparency of the predetermined price. Neither source of data required for the calculation -- the median bid price from the last CPE solicitation and the aggregated RA prices reported to Energy Division -- presents concerns regarding market sensitivity. The Energy Division prices are made public annually, and the median CPE price would reveal very little about the stratification of bids actually accepted by the CPE.

4. Bidding issues

On the issue of whether the mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation, both PG&E and CalCCA argued that the LSE would need to choose between voluntarily showing (for mechanism eligibility) and bidding / showing as part of the solicitation process. CESA argued that the LSE should not be precluded from also bidding and showing. SCE recommended that this topic be further discussed in workshops to address issues of gaming risk.

CalCCA also proposes a price formula for the pre-determined price. The "pre-determined price" calculation would be calculated as follows:

> Year 1: Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> Subsequent Years: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

An LSE could choose to show its preferred or energy storage resources to the CPE for local credit at a price lower than the pre-determined price if desired.

5. Annual adjustments to local compensation

Parties had differing views on how frequently the mechanism should be adjusted. PG&E advocated that the premium should be updated annually to reflect the most recent CAISO Local Capacity Technical Study Report. CESA argued that an annual adjustment would not be necessary. Others argued that annual adjustments would ultimately depend on the details of the mechanism (SCE).

Because CalCCA proposes comparison of the shown resource alongside bid resources, as D.20-06-002 requires, CalCCA proposes no annual adjustment to the compensation. Bid resources are not adjusted annually for effectiveness but are paid as bid. In the same way, shown resources should be paid for the term of the showing at the pre-determined price (or below).

6. Bid evaluation process

On the question of how the CPE should incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources, there were several disparate ideas. SCE argued that the question should be addressed in CPE implementation as it relates to the bid selection process and bid selection criteria and how the CPE will fairly implement the least-cost-best-fit procurement criteria. CEDMC argued that both qualitative and quantitative criteria be considered, and preferred resources should be favored over fossil-fueled resources. CESA argued that the criteria should link to integrated-resource-plan-identified future long-term procurement needs in local or sub-local areas and adhere to the loading order and SB 1136 statutory requirements to the greatest extent possible.

7. Treatment of existing contracts

There were several proposals relating to the treatment of existing contracts that spanned a cutoff date for qualification, the period over which a contract should qualify, and whether UOG should qualify.

On the issue of a cutoff date, PG&E ~~and SCE~~ advocated that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired prior to the date of issuance of D.19-02-022, March 4, 2019. CalCCA argued that the mechanism should be applied to existing contracts entered into by an LSE on or before June 11, 2020. SCE stated that the cut-off date should be around the date when the Proposed Decision or the Final Decision was issued, i.e., either March 26, 2020 or June 11, 2020; while SCE is not opposed to PG&E's proposed March 4, 2019 cut-off date.

On the issue of the period over which a contract should qualify, SCE argued that it should be for up to a five-year term length. PG&E also stated that legacy treatment should not apply for the full term of the existing contract or owned resource. CalCCA recommends that the term be consistent with the terms sought for bid resources.

Lastly, on the issue of UOG, CalCCA argued that UOG should not be eligible, while PG&E advocated for eligibility for UOG.

V. Consensus and Non-Consensus Around Full LCR RCM Proposals

A. CalCCA's Proposal (Option #2)

CalCCA offered a complete proposal (Option #2) for the LCR RCM, summarized in their comments as follows:

Shown Resources Compared Alongside Bid Resources	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	No annual adjustment for effectiveness.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or the LSE's lower shown price) for the local RA premium.
Premium Granularity	Local area or sub-area unless aggregation up is required to mask individual resource prices; no technology differentiation in pre-determined price.
Showing Term	LSE may show a resource for whatever term the CPE permits for its solicitations, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show its local RA attributes and receive the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing owned fossil resources do not qualify for a local showing.

Several parties expressed interest in this proposal, although there was not broad consensus reached from all parties involved in the WG. Both Calpine Corporation and AReM submitted informal comments questioning the concept of permitting bids outside of the auction process and suggesting that there should be "full flexibility to specify the prices at which shown resources will be compared to bid resources" in the CPE's auction to provide LSEs "incentives to offer competitively to ensure that their resources are selected over offered resources." AReM observed that all options for a compensation mechanism have risks for market power and gaming

and questioned "if the limited potential benefits warrant moving forward with any compensation mechanism."

PG&E submitted comments in reply to CalCCA's proposal (Option #2) stating that PG&E did not find that the proposal clearly meets all of the objectives in D.20-06-002; however, PG&E believes it is reasonable and the only workable solution that has been put forth by the WG that clearly meets the objective of allowing LSEs to retain the system and flexible RA attributes and receive compensation for the local RA attribute under the hybrid procurement framework. If the Commission is willing to consider this proposal, PG&E believes that (i) all LSEs, including IOUs, should be able to avail themselves of the LCR RCM in the same manner (which requires the Commission to revisit IOU bidding requirements in D.20-06-002 in a new track of the RA proceeding or identify another venue to evaluate the bidding requirements for IOUs to participate in the LCR RCM proposed by CalCCA in Option #2), and (ii) LSEs should continue to be afforded the "voluntarily shown" option, without compensation under the LCR RCM, should LSEs want to retain the system/flexible RA products for use toward its LSE-specific system and flexible RA requirements.

SCE also submitted comments in reply to CalCCA's proposal (Option #2) stating that there are merits to the proposal, and it should be further explored. SCE recommended a few clarifications to the proposal, including (i) if a shown resource is selected by the CPE during the solicitation, then the LSE should be paid its offer price for the shown resource, not the pre-determined premium, and (ii) the option of showing a local resource without direct compensation should be retained and made available to all LSEs.

B. SDG&E's Proposal

As described in Section III.B, SDG&E also provided a full proposal on the LCR RCM. PG&E submitted comments on SDG&E's proposal expressing concerns that the proposed methodology does not appropriately addresses cost effectiveness concerns. PG&E believes that it may overestimate voluntarily shown resources, which may result in customers paying for resources that do not provide any ratepayer value or any local area reliability benefits to the system. Additionally, PG&E has concerns with SDG&E's proposal on local premium price, as this methodology is similar to the financial crediting mechanism proposed by CalCCA in Rulemaking 17-09-020 that was rejected by the Commission and specifically excluded from the scope of consideration in this Track.

Exhibits

Exhibit A: July 6, 2020 Service Email

Exhibit B: July 20, 2020 Informal Comments

Exhibit C: July 27, 2020 WG Workshop Presentations

Exhibit D: August 3, 2020 Informal Comments

Exhibit E: August 17, 2020 Informal Reply Comments

Exhibit F: August 26, 2020 Informal Comments on Draft Report

Exhibit G: Final Matrix of Party Positions

Subject:	R.19-11-009 (RA): SDG&E Proposed Revision to Draft RA Track 3.A Working Group Report - 1 of 2
Date:	Wednesday, August 26, 2020 at 11:23:00 AM Pacific Daylight Time
From:	Evans, Darleen
CC:	Smith, Aimee, Chase, Tina
Attachments:	image002.png, (DRAFT) Co-Leads Working Group Report on LCR RCM and Treatment of Existing Contracts (SDG&E).docx, R.19-11-009 COS.pdf

As requested by the co-chairs of the RA Track 3.A Working Group on Local Capacity Requirement (LCR) Reduction Compensation Mechanism (RCM) and Treatment of Existing Contracts, attached please find SDG&E's proposed revisions to the Draft Working Group Report.

Note: This service will be sent in multiple parts due to Microsoft restrictions that limit the number of recipients for each individual email.

Thank you.

Darleen Evans
On Behalf of Aimee M. Smith
San Diego Gas & Electric Company

ATTACHMENT 1 TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) TRACK 3.A WORKING GROUP REPORT ON CONSENSUS AND NON-CONSENSUS ITEMS REGARDING DEVELOPMENT OF LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND PROPOSAL ON TREATMENT OF EXISTING CONTRACTS

WORKING GROUP REPORT

[TABLE OF CONTENTS TO BE INSERTED]

Working Group Report on Consensus and Non-Consensus Items Regarding Development of Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Proposal on Treatment of Existing Contracts

I. Background

A. Procedural Background and Scope

Decision (D.) 20-06-002 adopts implementation details for the central procurement of multi-year local resource adequacy (RA) to begin for the 2023 compliance year in the Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) distribution service areas, including identifying PG&E and SCE as the central procurement entities (CPE) for their respective distribution service areas and adopting a hybrid central procurement framework.[1] The framework places full local RA procurement responsibility on behalf of all load serving entities (LSE) on the CPE, and LSEs no longer receive individual local requirements.[2] LSEs that have procured local resources may "(1) show the resource to reduce the central procurement entity's (CPE) overall local procurement obligation and retain 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."[3] Under the "show" option, the LSE does not receive one-for-one credit for its local resources.[4]

In adopting the hybrid central procurement framework, the California Public Utilities Commission (Commission) found that, even without a financial crediting mechanism, the framework does not disincentivize procurement of local resources because LSEs procure local

[1] D.20-06-002 at 1, Ordering Paragraphs 2-4.
[2] *Id*. at 22-23, Ordering Paragraph 3.
[3] *Id*. at 23, Ordering Paragraph 4.
[4] *Id*. at 23.

resources for many reasons beyond the local RA value.[5] The Commission recognized, however, that "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas."[6] To that end, the Commission committed to developing a "financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value" (LCR RCM), if details can be assessed and developed.[7] To develop such a mechanism, the Commission directed a working group (WG) co-led by CalCCA and either PG&E or SCE.[8] The Commission also included within the scope of the WG issues related to treatment of existing contracts, including potential application of the LCR RCM to these contracts.[9] The Commission further required the co-leads to file a WG report on consensus and non-consensus items (Report) in this proceeding by September 1, 2020. In addition, the assigned Commissioner in this proceeding issued the *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling*, dated July 7, 2020 (Amended Scoping Memo), designating evaluation of an LCR RCM as an issue in Track 3.A and requiring WG reports and proposals from parties to be filed on September 1, 2020.

In both D.20-06-002 and the Amended Scoping Memo, the Commission identified four specific issues to be addressed by the Report:[10]

a. How granular the premium should be (*e.g.*, should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);

b. How to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

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5 *Id*. at 40-41, 72.
6 *Id*. at 42, 72.
7 *Id*., at 43.
8 *Id*. at Ordering Paragraph 5.
9 *Id*. at 46, 75 and Ordering Paragraph 6.
10 *Id*. at Ordering Paragraph 5.

c. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process; and

d. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

In addition, the Commission directed in D.20-06-002 that the Report "address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources."[11] D.20-06-002 also requires the WG to (i) "consider and submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing contracts"[12] and (ii) consider how the CPE will incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small."[13] The Report must also address consensus and non-consensus items regarding treatment of existing contracts.[14]

Using this guidance, CalCCA and PG&E, serving as WG co-leads, sent an email to the service list on July 6, 2020, soliciting initial input from stakeholders through informal comments submitted on July 20, 2020, and seeking participation by other stakeholders with an interest in presenting at a WG workshop on the identified issues set for July 27, 2020.[15] Eight parties submitted informal comments on the 7 Issues on July 20, 2020 ahead of the July 27, 2020 WG

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[11] *Id.* at Ordering Paragraph 5. The Amended Scoping Memo includes a similar requirement. Amended Scoping Memo at 3.

[12] *Id.* at Ordering Paragraph 6.

[13] *Id*. at pp. 44-45. The four issues identified above (a.-d.) and the three issues identified in this paragraph (i.e. in the first sentence and romanettes (i) and (ii) of the second sentence) are referred to herein as the "7 Issues." The 7 Issues are also outlined in the email attached as Exhibit A.

[14] *Ibid*.

[15] The email to the service list laying out the WG schedule is attached as Exhibit A.

workshop. These informal comments are attached as Exhibit B to this Report. Three parties (PG&E, CalCCA, and San Diego Gas & Electric Company (SDG&E)) expressed interest in presenting at the WG workshop. The co-leads facilitated the WG workshop by WebEx on July 27, 2020, beginning at 10:00 a.m. The co-leads jointly presented a review of the 7 Issues identified in D.20-06-002 and initial informal comments on the 7 Issues. Additionally, PG&E made a presentation as a participant in the WG to address pending issues. CalCCA also presented as a WG participant, offering two proposals. The only other party presenting a proposal was SDG&E. These presentations are attached as Exhibit C. WG participants submitted informal comments and replies regarding the WG workshop on August 3, 2020, attached as Exhibit D, and on August 17, 2020, attached as Exhibit E, respectively. A draft of the Report was circulated to WG participants on [August 21, 2020], with informal comments on the draft Report submitted on [August 26, 2020] and attached here as Exhibit F.

The workshop and parties' informal comments have helped inform this Report.

B. Topics Expressly Excluded from Scope

The Commission expressly identified certain topics as out-of-scope.[16] They include:

1. One-for-one credit mechanism for local RA that does not account for relative effectiveness of shown resources relative to bid resources;[17]

2. Ex-post price premium based on the average price paid by the CPE for resources in the local area for which a resource is shown;[18]

3. Credit mechanism for fossil fuel resources (other than potentially for existing contracts);[19] and

[16] D.20-06-002 at 43 ("The Commission is not open to considering a one-for-one credit, CalCCA's proposed financial credit mechanism, or a credit mechanism for fossil fuel resources (other than potentially for existing grandfathered contracts).").

[17] *Id*. at 41.

[18] *Id.* at 42.

[19] *Id.* at 41.

4. An LCR RCM mechanism for the SDG&E Transmission Access Charge (TAC) area, where a CPE will not be designated. [20]

Stakeholders generally adhered to this guidance in offering proposals presented through the WG process and described in this Report.

C. Schedule of Completed Activities

The co-leads scheduled and completed the following WG activities:

Date	Activity	Status
July 6, 2020	Co-leads circulated notice to the service lists of WG co-leads and WG schedule, including workshop, and request for informal comments on 7 Issues outlined in D.20-06-002 on pages 43-45 and in Ordering Paragraphs 5 and 6.	Complete
July 17, 2020	Co-leads circulated notice of workshop date and call-in information to the service lists.	Complete
July 20, 2020	Parties submitted informal comments to the service lists in response to the co-leads' request on 7 Issues outlined in D.20-06-002 and notified co-leads of intent to present at workshop.	Complete
July 24, 2020	Co-leads circulated notice of agenda and presentation materials for the virtual workshop to service lists.	Complete
July 27, 2020	Co-leads hosted a virtual workshop on WebEx on LCR RCM and the treatment of existing contracts.	Complete
July 30, 2020	Co-leads again circulated presentations from virtual workshop to workshop participants, in addition to a matrix for parties to utilize in developing informal comments on the workshop.	Complete
July 31, 2020	Co-leads circulated updated schedule for WG to the service lists, including dates for informal reply comments on workshop, issuance of a draft Report, and informal comments on the draft Report.	Complete

[20] *Id.* at Conclusion of Law 6.

August 3, 2020	Parties submitted informal comments on the workshop to co-leads, which were circulated to the service lists on August 4, 2020.	Complete
August 17, 2020	Parties submitted informal reply comments on the August 3 informal comments to the service lists (PG&E's informal reply comments were sent to the co-leads on August 17, 2020, and to the service lists on August 19, 2020).	Complete
August 20, 2020	Co-leads circulated an updated schedule for the WG to the service lists	Complete
August 21, 2020	Co-leads served a draft Report to the service lists for comment.	Complete
August 26, 2020	Parties submitted informal comments on the draft Report to the service lists.	[Complete]
September 1, 2020	Co-leads filed and served Report.	[Complete]

II. Guiding Principles and Objectives

The co-leads presented their views and interpretations on guiding principles and objectives in the July 27, 2020, workshop presentations.

A. Guidance from D.20-06-002

Drawing from D.20-06-002, the co-leads identified the following explicit guidance provided by the Commission, with the corresponding page number or ordering paragraph (OP) in brackets:

<u>Effectiveness:</u>

1. The LCR RCM cannot provide a "one for one" premium as CalCCA proposed without considering effectiveness. [p. 41]
2. The LCR RCM must address "local effectiveness" and "use limitations" of the shown resource to align the financial compensation with the actual LCR MW reduction the resource provided. [p. 42, OP 5]
3. The WG should consider how to adjust payments to an LSE "from year to year to account for changes in the effectiveness of the resource reducing local requirements." [OP 5.d.]

4. CPE selection criteria must include (1) "Local effectiveness factors, as published in the California Independent System Operator's Local Capacity Requirement Technical Studies" [OP 14.b.] and "Energy-use limitations" [OP 14.h.]

Least-Cost, Best-Fit:

a. "Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSE's seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE" [p. 42]
b. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]
c. "[E]nsures that ratepayers are: (1) only compensating resources to the extent they provide ratepayer value…" [p. 43]

Premium Determination and Market Power Issues:

1. The LCR RCM should "only compensate [] LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs" [p. 43]
2. "[T]he CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources" [p. 42]
3. A "benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums" [p. 42]
4. "To the extent that market power inflates local area capacity prices, an ex post benchmark would exacerbate this problem by providing inflated prices to local resources shown by LSEs" [p. 42]
5. The WG must determine "[h]ow to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices." [OP 5.b]

Preferred Resource Development in Local Areas

1. "a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas." [p. 41]

B. PG&E Proposed Principles

Based on the guidance in D.20-06-002, PG&E outlined the following four recommended principles for the LCR RCM in its workshop presentation included in Exhibit C:

- The LCR RCM should:

- Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;
- Reflect the effectiveness of a resource at meeting reliability requirements to prevent "leaning" by LSEs;
- Result in lower total costs to customers without sacrificing local area reliability; and
- Not be reflective of market power and/or introduce gaming opportunities but may reflect a "premium" based on the additional cost of developing resources in local areas.

WG participants also provided recommendations and comments on guiding principles.

The Alliance for Retail Energy Markets (AReM) proposed the following principles in the evaluation of the need and structure for any such compensation mechanism:

- No CPE Over-procurement - The ability for an LSE to receive an LCR RCM payment from the CPE must not result in over-procurement by the CPE with those costs spread among all LSEs;
- Cost Causation – Customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; costs should not be spread to other LSEs or their customers;
- Premiums Paid for Shown Resources Must Be Aligned with the Auction – LSEs with resources worth a premium to the CPE should be eligible for compensation up to that premium not more; and
- Payment Length for Show Resources Must Be Aligned with the Local RA Requirement – The number of years an LSE is eligible for an LCR RCM payment should not be longer than up to three years – the term of the Local RA requirement.

California Energy Storage Alliance (CESA), in addition to responses to the specific 7 Issues presented, also suggested that the WG should:

- consider pathways to maintain the load forecast adjustment process that is specific to an LSE and reflected in their pro rata share of the collective local RA requirements, and
- clarify and discuss the implications of the CPE buying all RA attributes if selected.

III. Description of Proposals

A. CalCCA Proposals

1. CalCCA Option #1

CalCCA's initial proposal, presented in its July 20, 2020, informal comments, advanced a CPE "must take" model. The model evolved as a result of the workshop and Parties' comments, however, into a refined "Option #1" proposal presented in CalCCA's July 27, 2020, comments. CalCCA does not recommend adoption of this approach but prefers its "Option #2" described below.

Under the must-take model, the CPE would be bound to take any local RA attributes from preferred or energy storage resources shown by an LSE. The price would be determined using the following formula:

> <u>Year 1:</u> Use the median price from the last four quarters of Energy Division Power Charge Indifference Adjustment (PCIA) responses for both system and local RA; subtract system RA price from local RA and multiply by effective megawatt (MW)
>
> <u>Subsequent Years:</u> Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

This formulation removes the risk of market power influence by relying on the *median* CPE bid price rather than an *average* bid price. The median price is also unlikely to suggest pricing to future bidders, which an average price would do.

The number of MW shown by the LSE would be adjusted for effectiveness, using one of two methods. The first method would rely on published California Independent System Operator Corporation (CAISO) effectiveness factors, scaling a resource's effectiveness to the average effectiveness procured by the CPE in that specific local area. Because these factors do not fairly represent the value of resources, due to their focus on a limited subset of constraints, CalCCA

did not favor this approach. The second method would rely on a yet-to-be determined methodology using data regarding peak contribution of particular technologies in specific local areas and data underlying the CAISO's identified storage need in its annual Local Capacity Technical Study. CalCCA pointed out, however, that developing these technology-specific methodologies would be time consuming and would, at best, provide only rough justice in determining the showing value.

CalCCA does not support adoption of Option #1 due to the complexity of developing reasonable effectiveness calculations. In addition, it is difficult to square a CPE "must-take" model with the directive in D.20-06-002 that shown resources must be "evaluated alongside bid resources."

2. CalCCA Option #2

CalCCA advances its Option #2 as the preferred methodology for the LCR RCM. Unlike Option #1, the CPE would not be bound to accept all shown resources but could reject them after considering their value "alongside bid resources." The "pre-determined price" calculation would be the same as Option #1:

> <u>Year 1:</u> Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> <u>Subsequent Years:</u> Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

The only difference is that an LSE could choose to show its resources to the CPE for local credit at a price lower than the pre-determined price if desired.

The primary benefit of this approach, however, is administrative simplicity. Option #2 does not require further work to develop highly technical, technology-specific effectiveness

values. Instead, it relies on the guidelines the CPE will use to evaluate bid resources. In other words, the CPE would apply the same methodology or considerations to *bid* and *shown local RA* resources in comparing their value.

Beyond these fundamental features, CalCCA addressed term and documentation of showings. Resources committed through a showing would have a three-year commitment where the term start date could be any year within the three-year forward compliance period. The showing (like bid) would be documented through a confirm under the Edison Electric Institute (EEI) Master Agreement.

3. CalCCA Proposal on Treatment of Existing Contracts

In essence, since preferred and storage resources are covered by the showing option, the legacy treatment for existing contracts identified by D.20-06-002 LCR RCM would only apply to existing fossil contracts. The Commission did not extend this same authority for an investor owned utility (IOU) to show fossil utility owned generation (UOG). As stated in D.20-06-002, existing fossil UOG would be required to bid into the CPE solicitation, and bid UOG would receive Cost Allocation Mechanism (CAM) treatment.[21]

CalCCA proposes that existing fossil contracts receive legacy treatment for five years from the implementation of the CPE. Legacy contracts will include only resources that are currently online and were contracted by an LSE on or before June 11, 2020 (the date D.20-06-002 was issued).

Summary of CalCCA Option #2 LCR RCM Recommendation	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.

[21] D.20-06-002 at 48.

Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	If selected, LSE will be paid the showing price (pre-determined price or below) without annual adjustment for effectiveness, like bid resources.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose (see §b. above.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or lower if the LSE showed at a lower price) for the shown resource.
Premium Granularity	Price is differentiated by local area or sub-area, unless aggregation up is required to mask individual resource prices; not technology-specific prices.
Showing Term	LSE may show a resource for a term of up to three years, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show for the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing UOG "resources" do not qualify for a local showing.

B. SDG&E Proposal

SDG&E developed a proposal, included it in their July 20, 2020 comments, and presented the proposal at the July 27, 2020 workshop. SDG&E's proposal addressed resource applicability, local premium, effectiveness factors, duration, and cost-allocation.

On resource applicability, SDG&E noted that the LCR reduction compensation mechanism would apply to only three categories of shown resources:

1. All energy storage;

2. All preferred resources; and

3. Grandfathered contracts of existing fossil fuel resources.

On the local premium, SDG&E proposed that the CPE utilize the relevant Power Cost Indifference Adjustment (PCIA) System RA Market Price Benchmark (MPB) for its area, either NP-15 or SP-15 for the compliance year. SDG&E noted that the System RA MPB is typically available in November prior to the compliance year. SDG&E suggested consideration of the weighted average price of Local resources that were contracted by the CPE for the compliance year. This means that the CPE must identify the specific cost related to RA capacity procured if it procured other attributes, such as Flexible RA or energy tolling, which is necessary to ensure an apples-to-apples comparison. SDG&E also explored using the PCIA Local MPB, however it was unclear how the CPE procurement of Local resources would impact the PCIA Local MPB calculation. Therefore, SDG&E recommended using prices relevant to CPE procurement. SDG&E also maintained that both values could be made publicly available in November after the CPE has finished its procurement along with the publication of the annual PCIA MPBs.

On effectiveness, SDG&E ~~argued~~ recommended that effectiveness factors should be guided by the CAISO and the annual Local Capacity Technical Study (LCTS). However, since that methodology may be too complex, SDG&E offered a simpler alternative until a more precise methodology can be adopted. SDG&E proposed that the effectiveness factors for all shown resources be calculated based on the percentage resulting from the local or sub-area LCR divided by the total amount of capacity shown and CPE procured capacity. SDG&E provided the example that if the LCR is 100 MWs and 40 MWs were shown by LSEs, and 80 MWs were procured by the CPE, the percentage would be 100 MW / 120 MW, or 83.33 percent. LSEs that showed the total of 40 MWs would receive a credit of approximately 33.33 MWs.

In terms of duration, SDG&E proposed that the resources would be shown annually on a three-year rolling basis. SDG&E's proposal provided a process for how capacity would be continue to be shown as well as offered in future years to the CPE.

For cost-allocation, SDG&E proposed that the premium associated with the shown local RA capacity would reduce the costs allocated to the LSE by the CPE for the procurement.

C. PG&E Presentation and Proposals

While PG&E did not present a full proposal at the July 27, 2020 workshop, PG&E's presentation included proposed guiding principles for the LCR RCM, detailed above in Section II and repeated here for convenience:

- The LCR RCM should:
    - Incent preferred resource development in local areas to reduce dependence on fossil-generation for reliability;
    - Reflect the effectiveness of a resource at meeting reliability requirements to prevent "leaning" by LSEs;
    - Result in lower total costs to customers without sacrificing local area reliability; and
    - Not be reflective of market power and/or introduce gaming opportunities but may reflect a "premium" based on the additional cost of developing resources in local areas.

PG&E's presentation explained that PG&E had not identified a mechanism for developing a price that clearly met these proposed guiding principles. In attempting to establish an appropriate local price, PG&E considered two options: cost-based and market-based. PG&E discussed how each of these prices could be derived and outlined the drawbacks of each option. PG&E also proposed that the LCR RCM premium should be as granular as possible in order to send the correct market signals.

PG&E further explained its view that any "workable" solution must be paired with a transparent and appropriate effectiveness adjustment and demonstration of reduction in total costs to customers. PG&E's presentation provided information regarding the complexity and potential infeasibility of developing effectiveness adjustments using CAISO effectiveness factors, as well as other measures of effectiveness that could be explored.

PG&E concluded its presentation by stating that the LCR RCM should not result in an increase in total costs to customers. In other words, resources paid through this mechanism must be lower cost than its alternative, and the mechanism must not be game-able.

In addition, PG&E utilized the July 20, 2020, informal comments to provide its proposals with respect to treatment of existing contracts and existing owned resources. First, PG&E proposed that legacy treatment of existing contracts not be afforded to contracts for local resources that were procured outside of an LSE's transmission access charge (TAC) area (e.g. a northern California LSE that procured a resource within a southern California LSE's TAC), as those resources were not procured by the LSE to meet local RA requirements, but were likely procured to meet the LSE's system RA requirements. PG&E also proposed that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired, prior to the date of issuance of D.19-02-022, March 4, 2019 (i.e. when the Commission affirmed its intent to adopt a centralized procurement framework for local RA resources and the possibility that LSEs may no longer have a procurement obligation for local RA). PG&E also proposed that legacy treatment not be applied for the full term of an existing contract or the life of an existing owned resource.

IV. Consensus and Non-Consensus Items

A. Matrix of party positions

As part of the WG process, the co-leads developed a matrix of party positions that covers key questions, including effectiveness, granularity, transparency, bidding issues, annual adjustments, the evaluation process, and shows where there is consensus and non-consensus among parties. The matrix was distributed to workshop participants on July 30, 2020, and parties provided edits to the matrix as part of informal comments submitted on August 3, 2020. The matrix has been updated to incorporate edits submitted on August 3, 2020, and is included in this Report as Exhibit G.

B. Summary of Consensus and Non-Consensus Items for the 7 Issues

1. Cost-effectiveness

While some parties stated that the mechanism should not provide compensation if the resource does not provide value (CalPA) or does not reduce costs (PG&E), other parties argued that cost-effectiveness should not be in scope (CEDMC). Others raised feasibility of the mechanism if CAISO would need to provide information on effectiveness (SCE, SDG&E). Others argued that the CPE should produce multiple portfolios, akin to the transmission alternative portfolios the CAISO creates in the Transmission Planning Process, as a means to address cost-effectiveness (CESA).

With respect to how the mechanism should address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources, six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the topic should be within the scope of the mechanism and one party (CEDMC) stated that it should be outside of the scope of the mechanism.

PG&E and CESA expressed that a resource should demonstrate its effectiveness to receive compensation. CESA looks to have the assessment incorporate non-quantitative criteria, whereas PG&E looks to have only quantitative criteria used.

Six parties (CalCCA, CalPA, PG&E, SCE, SDG&E, and CESA) stated that the effectiveness adjustments could be determined by the CAISO through various mechanisms. The specific actions suggested by the parties varied, ranging from: adjustments to NQC values (PG&E), determination of effectiveness factors (SCE), using the Local Capacity Technical Study (SDG&E), and developing a stakeholder process for determining the appropriate mechanism (CalCCA).

CalCCA's final proposal (Option #2) left the question to the CPE. The CPE is required to take effectiveness into account in selecting bids from its solicitations. Since CalCCA's proposal (Option #2) contemplates a comparison of shown preferred resources alongside bid resources, CalCCA submits that the CPE should apply the same criteria – whatever they may be – to both bid and shown resources.

2. Premium granularity

There was a broad spectrum of perspectives on premium granularity. Some parties argued that the premium should be dependent on the data available; for example, it could be sub-area, local area, or TAC-wide area (SCE). Others argued for premiums for each resource technology type (CalPA) or by resource type, location, or operational characteristics (CEDMC), or based on location, including disadvantaged communities (DACs), GHG emissions reduction, and market power mitigation (CESA).

With respect to how granular the premium should be, three parties stated that the price premiums should be differentiated by local areas or sub-local areas (CalCCA, PG&E, and SDG&E) and one party stated that it should be differentiated by the TAC-wide area (SCE) unless a higher level of aggregation was required to mask the price of individual resource prices. SDG&E stated that it believed the complexity of developing individual premiums for the various types of resources in either sub-areas or local areas ~~-~~makes the task infeasible.

One party stated that a series of premiums should be stacked to arrive at the final premium for a resource (e.g., closer-to-load, within a DAC, GHG emission reduction, and offers market power mitigation) (CESA). An additional party referenced a premium for a resource being located within a DAC (CEDMC).

3. Transparency of premium

Parties broadly supported as much transparency as possible, while still protecting market-sensitive information. Parties presented numerous ideas on how and when data should be presented. For instance, PG&E advocated for aggregating data upfront and making more detailed data available after sufficient time had passed. CalPA argued for posting the premiums to the service list and CESA argued that premiums should be made available by resource class. SDG&E argued that advance knowledge of the premium is not necessary since LSEs ~~could still~~may have elected to show the resource if the offer is not selected by the CPE. The LSE does not lose any optionality in maximizing value for its customers.

CalCCA observed that its proposal would allow for full transparency of the predetermined price. Neither source of data required for the calculation -- the median bid price from the last CPE solicitation and the aggregated RA prices reported to Energy Division -- presents concerns regarding market sensitivity. The Energy Division prices are made public annually, and the median CPE price would reveal very little about the stratification of bids actually accepted by the CPE.

4. Bidding issues

On the issue of whether the mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation, both PG&E and CalCCA argued that the LSE would need to choose between voluntarily showing (for mechanism eligibility) and bidding / showing as part of the solicitation process. CESA argued that the LSE should not be precluded from also bidding and showing. SCE recommended that this topic be further discussed in workshops to address issues of gaming risk.

CalCCA also proposes a price formula for the pre-determined price. The "pre-determined price" calculation would be calculated as follows:

> Year 1: Use the median price from the last four quarters of Energy Division PCIA responses for both system and local RA; subtract system RA price from local RA and multiply by effective MW
>
> Subsequent Years: Use the median price from the last four quarters of Energy Division PCIA responses for system RA and the most recent reported CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and multiply by effective MW

An LSE could choose to show its preferred or energy storage resources to the CPE for local credit at a price lower than the pre-determined price if desired.

5. Annual adjustments to local compensation

Parties had differing views on how frequently the mechanism should be adjusted. PG&E and SDG&E advocated that the premium should be updated annually to reflect the most recent CAISO Local Capacity Technical Study Report. CESA argued that an annual adjustment would not be necessary. Others argued that annual adjustments would ultimately depend on the details of the mechanism (SCE).

Because CalCCA proposes comparison of the shown resource alongside bid resources, as D.20-06-002 requires, CalCCA proposes no annual adjustment to the compensation. Bid resources are not adjusted annually for effectiveness but are paid as bid. In the same way, shown resources should be paid for the term of the showing at the pre-determined price (or below).

6. Bid evaluation process

On the question of how the CPE should incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources, there were several disparate ideas. SCE argued that the question should be addressed in CPE implementation as it relates to the bid selection process and bid selection criteria and how the CPE will fairly implement the least-cost-best-fit procurement criteria. CEDMC argued that both qualitative and quantitative criteria be considered, and preferred resources should be favored over fossil-fueled resources. CESA argued that the criteria should link to integrated-resource-plan-identified future long-term procurement needs in local or sub-local areas and adhere to the loading order and SB 1136 statutory requirements to the greatest extent possible.

7. Treatment of existing contracts

There were several proposals relating to the treatment of existing contracts that spanned a cutoff date for qualification, the period over which a contract should qualify, and whether UOG should qualify.

On the issue of a cutoff date, PG&E and SCE advocated that legacy treatment should be applied only to local RA contracts executed, or owned resources that were acquired prior to the date of issuance of D.19-02-022, March 4, 2019. CalCCA argued that the mechanism should be applied to existing contracts entered into by an LSE on or before June 11, 2020.

On the issue of the period over which a contract should qualify, SCE argued that it should be for up to a five-year term length. PG&E also stated that legacy treatment should not apply for the full term of the existing contract or owned resource. CalCCA recommends that the term be consistent with the terms sought for bid resources.

Lastly, on the issue of UOG, CalCCA argued that UOG should not be eligible, while PG&E advocated for eligibility for UOG.

V. Consensus and Non-Consensus Around Full LCR RCM Proposals

A. CalCCA's Proposal (Option #2)

CalCCA offered a complete proposal (Option #2) for the LCR RCM, summarized in their comments as follows:

Shown Resources Compared Alongside Bid Resources	
CPE Obligation	CPE may accept or reject the showing if more cost-effective resources are available.
Effectiveness	CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	No annual adjustment for effectiveness.
Pre-determined Price	Pre-determined price set at median local RA price from last CPE solicitation less the most recent system RA prices; LSEs have the option to show their resources at a lower price if they choose.
Calculation of Payment	If selected, LSE will be paid the pre-determined price (or the LSE's lower shown price) for the local RA premium.
Premium Granularity	Local area or sub-area unless aggregation up is required to mask individual resource prices; no technology differentiation in pre-determined price.
Showing Term	LSE may show a resource for whatever term the CPE permits for its solicitations, with the term commencing within the current three-year compliance period.
Bid/Show Election	LSE may show or bid its resource, not both.
Existing Contracts	Contracts executed to convey local RA attributes from a third party to an LSE executed not later than June 11, 2020 (the date D.20-06-002 was issued) may show its local RA attributes and receive the local premium for the lesser of the remaining contract term and the end of the 2025 RA compliance year. Existing owned fossil resources do not qualify for a local showing.

Several parties expressed interest in this proposal, although there was not broad consensus reached from all parties involved in the WG. Both Calpine Corporation and AReM submitted informal comments questioning the concept of permitting bids outside of the auction process and suggesting that there should be "full flexibility to specify the prices at which shown resources will be compared to bid resources" in the CPE's auction to provide LSEs "incentives to offer competitively to ensure that their resources are selected over offered resources." AReM observed that all options for a compensation mechanism have risks for market power and gaming and questioned "if the limited potential benefits warrant moving forward with any compensation mechanism."

PG&E submitted comments in reply to CalCCA's proposal (Option #2) stating that PG&E did not find that the proposal clearly meets all of the objectives in D.20-06-002; however, PG&E believes it is reasonable and the only workable solution that has been put forth by the WG that clearly meets the objective of allowing LSEs to retain the system and flexible RA attributes and receive compensation for the local RA attribute under the hybrid procurement framework. If the Commission is willing to consider this proposal, PG&E believes that (i) all LSEs, including IOUs, should be able to avail themselves of the LCR RCM in the same manner (which requires the Commission to revisit IOU bidding requirements in D.20-06-002 in a new track of the RA proceeding or identify another venue to evaluate the bidding requirements for IOUs to participate in the LCR RCM proposed by CalCCA in Option #2), and (ii) LSEs should continue to be afforded the "voluntarily shown" option, without compensation under the LCR RCM, should LSEs want to retain the system/flexible RA products for use toward its LSE-specific system and flexible RA requirements.

SCE also submitted comments in reply to CalCCA's proposal (Option #2) stating that there are merits to the proposal, and it should be further explored. SCE recommended a few clarifications to the proposal, including (i) if a shown resource is selected by the CPE during the solicitation, then the LSE should be paid its offer price for the shown resource, not the pre-determined premium, and (ii) the option of showing a local resource without direct compensation should be retained and made available to all LSEs.

B. SDG&E's Proposal

As described in Section III.B, SDG&E also provided a full proposal on the LCR RCM. PG&E submitted comments on SDG&E's proposal expressing concerns that the proposed methodology does not appropriately addresses cost effectiveness concerns. PG&E believes that it may overestimate voluntarily shown resources, which may result in customers paying for resources that do not provide any ratepayer value or any local area reliability benefits to the system. Additionally, PG&E has concerns with SDG&E's proposal on local premium price, as this methodology is similar to the financial crediting mechanism proposed by CalCCA in Rulemaking 17-09-020 that was rejected by the Commission and specifically excluded from the scope of consideration in this Track.

<u>Exhibits</u>

Exhibit A: July 6, 2020 Service Email

Exhibit B: July 20, 2020 Informal Comments

Exhibit C: July 27, 2020 WG Workshop Presentations

Exhibit D: August 3, 2020 Informal Comments

Exhibit E: August 17, 2020 Informal Reply Comments

Exhibit F: August 26, 2020 Informal Comments on Draft Report

Exhibit G: Final Matrix of Party Positions

APPENDIX G

FINAL

MATRIX OF PARTY POSITIONS

Working Group on Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) and Treatment of Existing Contracts

		Matrix of Parties' Positions/Preferences			Summary of Parties' Informal Comments, submitt
No.	**Question**	**[Additional Question]**	**Calpine**	**California Efficiency + Demand Management Council**	**Alliance for Retail Energy Market (AReM)**
1	How should the mechanism address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources?	Should effectiveness be determined by using the: - **CAISO's Effectiveness Factors** - **CAISO's LCTS Contribution to Peak Load Methodology** - **CAISO's LCTS Energy Storage Limitation Study** - **Other**	Calpine believes that the mechanism should consider effectiveness related to the effectiveness factors that are included in the LCTS as well as duration/energy limits analyzed by the CAISO.	The Council does not support the use of any of these approaches for determining local effectiveness. The concept of resource-specific local effectiveness has not been addressed by the CPUC which should be done before applying it in this context.	N/A
2	How granular the premium should be (e.g., should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);	Should effectiveness adjustments be applied to the: - **Price premium** - **MW of shown capacity** - **Other**	Either an adjustment to the price premium or the MW credited could work.	N/A	N/A
		Should different **technology types** receive different premiums?	Different technologies should receive different credits with respect to their "effectiveness" as defined in response to question 1.	Not withstanding the Council's opposition to the use of local effectiveness factors, premiums should not be technology-specific. Using demand response as an example, whether the underlying technology is energy storage or customer load is irrelevant. Furthermore, the Loading Order, which serves as the basis for the CPUC's directive to favor preferred resources in CPE procurement, does not differentiate between technology types for renewables, demand response, or energy efficiency.	
		Should premiums be developed at the location level: - **TAC area only** - **Local area (e.g. Bay Area)** - **Sub-local area (e.g. South Bay / Moss Landing)**	Premiums should reflect the fact that resources in different locations, including different sub-areas, have different "effectiveness."	Locational premiums should only be applied at the subLAP or LCA level.	
3	How to make the premiums as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;	Should the premiums be: - **Publicly posted** - **Confidential** - **Other**	As indicated in Calpine's informal comments, Calpine believes that CalCCA's Straw Proposal #2 warrants further exploration. Under this approach, given that the CPE would be able to compare shown and bid resources in the solicitation, it is unclear why it would be necessary to establish pre-specified premiums for shown resources. Instead, if the proposal is ultimately adopted, the Commission should consider giving LSEs full flexibility to specify the prices at which shown resources will be compared to bid resources in the CPE solicitations recognizing that this structure would provide LSEs incentives to offer competitively to ensure that their resources are selected over offered resources and that the CPE would have the discretion to not "procure" shown resources and defer to CAISO backstop procurement in the absence of sufficient competition.	Premiums should be publicly posted for transparency and to promote the development of resources that are most highly valued.	N/A
		To balance transparency and market sensitive information, how should the data be presented: - **Aggregated** - **Individual** - **Other**		N/A	
		Should the premiums or effectiveness adjustments be: - **Published by the Commission** - **Other**		Premiums and effectiveness adjustments should be published by the CPUC.	
4	Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process;	Should the mechanism allow LSEs to: - **Bid and show** - **Bid or show** - **PG&E's proposal (if an LSE voluntarily shows, the LSE cannot select the option to both bid and voluntarily show the resource as part of the CPE's solicitation process)** - **Other**		N/A	N/A
5	How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.	Should the premium be: - **Fixed for the term of the commitment** - **Adjusted year to year** - **Other**	If something like CalCCA's Straw Proposal #2 were adopted, presumably shown resources would have the same certainty with respect to compensation as resources that are offered directly into the CPE solicitations, i.e., if the "bid" associated with a shown resource were selected, it would be paid its bid for the term of the commitment for which it was selected.	Any premium should be fixed for the term of the commitment. Otherwise, it would create revenue uncertainty and discourage development of the desired resources.	N/A
6	How should the CPE incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small?	In the Workshop, parties agreed that this should be addressed in a working group or through future proposals made in the RA proceeding, as suggested by the Commission (page 53-54 of D.20-02-006)		This issue should be addressed as expeditiously as possible. An initial, simple approach could be to use a multiplier to ensure that preferred resources receive extra value in the bid stack of CPE solicitations.	N/A
7	In addition, please provide any informal comments on the treatment of existing contracts, including whether any proposed local capacity requirement reduction compensation mechanism should be applied to existing contracts and for what period of time.	What should be the **cut off date** for legacy treatment of existing contracts?		N/A	N/A ~~Compensation mechanism adopted for preferred resources should be applied to existing contracts entered into by an LSE before June 11, 2020; not apply to fossil utility owned generation (UOG), which will be required to bid into the solicitation.~~
		What are the **terms (length of time)** for applying legacy treatment of existing contracts?		N/A	
		What should be the **eligibility rules** for the treatment of existing contracts?		N/A	
8		**Other**			
9		**Overall**	See informal comments.		1. The ability for a LSE to receive a payment from the CPE must not result in over-procurement by the CPE with the over-procurement costs spread among all LSEs. 2. The customers of LSEs with procurement costs above the CPE's auction prices should not receive a credit for above-market costs and should directly bear those costs themselves; they should not spread those costs to other LSEs or to the customers of other LSEs. 3. To the extent payments for shown resources are determined to be warranted, LSEs with such resource types that are worth a premium to the CPE should be eligible for compensation up to that premium. 4. The number of years of compensation for which a LSE is eligible for a LCR Reduction Compensation Mechanism payment should be for no longer than up to three years – the term of the Local RA requirement.

ed July 20, 2020

California Community Choice Association (CalCCA)	California Energy Storage Alliance (CESA)	California Efficiency + Demand Management Council (Council)
Incorporated not through a price reduction, but into a technology-specific modification of the megawatt (MW); California Independent System Operator (CAISO) should lead a stakeholder process to develop factors that could be used.	Favors an approach where the central procurement entity (CPE) request for offer (RFO) considers identifying multiple portfolios of bid and shown resources that, on one end, considers effectiveness as the binding, initial screening criteria and, on the other end, more heavily considers preferred attributes while ensuring effectiveness.	The CPUC should focus at least initially on a more simplistic approach, given the time contraints involved. Cost effectiveness of local resources should not be within the scope of the mechanism. Use limitations of resources should not be considered other than in the context of ensuring that MCC Bucket limitations are not violated. Local effectiveness of individual resources has not been defined by the CPUC and might be impractical for application to DR resources due to the sometimes dynamic nature of their customer and technology composition.
Price premiums would be differentiated by local areas, including the disaggregated "PG&E Other" areas, unless a higher level of aggregation were required to mask the price of individual resource prices.	Generally supports granularity of the LCR reduction compensation mechanism and proposed the following premiums for consideration (1) closer-to-load, (2) Disadvantaged communities (DAC), (3) Greenhouse gas (GHG) emissions reduction and (4) market power mitigation; A one-size-fits-all premium may undercut the incremental value-add of certain projects.	Factors on which to base a premium can be resource location, resource type (especially preferred resources), or operational characteristics or for resources located in DACs.
N/A	One way to balance transparency with the need for confidentiality would be to consider base class-specific premiums that are broadly applicable to all resources within that class.	Should be as transparent as possible to ensure that resource providers can develop the products of greatest value. For similar reasons, each CPE's least-cost, best-fit methodology should be made as transparent as possible.
Load serving entity (LSE) must chose to either bid or show.	LSE may bid and/or show.	N/A
N/A	Year-to-year adjustment to the local compensation mechanism should not be established and may not be needed.	N/A
N/A	CPE RFO evaluation criteria mirror the premium factors in the local compensation mechanism, link to IRP-identified future long-term procurement needs in local or sub-local areas, adhere to the loading order and SB 1136.	Both qualitative and quantitative criteria should be considered; pursuant to D.19-06-002, preferred resources should be favored over fossil-fuel resources and not disadvantaged, fairly compared to existing, fully-depreciated gas resources on a cost basis; greater consideration to low- or zero-emission resources in meeting State's environmental goals.
N/A	N/A	N/A
Use of a median referent price, which is unaffected by high outliers in a price distribution. Recommends that resources be committed for a three-year term; Showing, like a successful bid, should be documented through a confirm.		

Pacific Gas and Electric Company (PG&E)	Public Advocates Office (CalPA)	Southern California Edison Company (SCE)	San Diego Gas & Electric Company (SDG&E)
Local resources are not equally “effective” in meeting local area reliability needs; Should only be compensated for resources that either have been demonstrated to meet up-front eligibility requirements or have an effectiveness adjustment applied to the net qualifying capacity (NQC).	The effectiveness and ability of a resource to provide those local resource adequacy (RA) attributes should match or exceed the requirements of the Commission and/or CAISO that qualify specific technologies' ability to count as local RA.	Local effectiveness is determined by CAISO based on the fleet of resources available and the contingencies that the fleet meets; CAISO would need to provide the information on effectiveness factors and the value of use-limited resources in meeting a local area need in its LCR studies.	Should be guided by the CAISO and the annual Local Capacity Technical Study. However, SDG&E offers a simpler solution based on total CPE procured MWs and Shown relative to the LCR.
Ideally, the proposed compensation mechanism would be calculated for each sub-local area; Should reflect the contribution of a resource type to local area reliability.	There should be pre-determined premiums calculated for each resource technology type.	The premium should reflect the actual contribution to the local RA need of a resource and market conditions; The level of granularity should consider, and very likely depend on, data availability and the robustness of the data that report historic RA prices for these areas.	Proposes single premium for all resource types. Premium can be local area specific or broken down into sub-areas if sufficient data is available. Believes the complexity of developing individual premiums for the various types of resources in either sub-areas or local areas makes this task infeasible.
Potential options include publishing aggregated data upfront and more granular data after a sufficient period of time has passed or publishing rankings (e.g., highest value area to lowest) or tiers with ranges (e.g., top five local premiums include these areas and are between $5 and $7).	The Commission should post the premium and include them in both its annual RA Report and the annual Final RA Guide; This may not be feasible if a premium is created for each unique resource since it may be calculated depending on market sensitive resource information.	The transparency of the premiums would depend heavily on the data used to determine the premiums.	Utilize CPE procured costs compared to PCIA System Market Priced Benchmarks.
LSE may 1) voluntarily show a resource for local premium but may not bid or 2) bid and voluntarily show the resource for no local premium.	N/A	Due to complexity, recommends this be discussed in workshops evaluating gaming risk.	Compensation Mechanism is only applicable for resources that either Show or Bid and Show if not selected.
Any effectiveness adjustment to local premiums should reflect the assumptions and findings of the most recent CAISO Local Capacity Technical Study Report.	Premium would increase or decrease as NQC is adjusted year to year.	Depends on details of the mechanism on how the effectiveness of resources is considered in deriving a premium.	Compensation Mechanism adjusts annually based on the capacity that CPE procured and Shown, the updated LCR, the CPE procurement costs and the PCIA System RA MPB
N/A	N/A	Recommends to be addressed in the area of CPE implementation as it relates to the bid selection process and criteria.	N/A
Legacy treatment of LSE's local RA existing contracts should be applied only to contracts executed, or owned resources that were acquired, prior to issuance of D.19-02-022(3/4/2019); not to local resources procured outside of the LSE's transmission area charge (TAC) area; do not support being applied for the full term of an existing	N/A	Apply to only those existing resources signed before the issuance of central procurement decision on 3/26/2020; for new resources it could apply to contracts signed prior to the PD, therefore limitation is only for local RA contracts with existing resources - up to a five-year term length.	Do not propose a separate rule for existing contracts, but not opposed to a one-time election exceeding the rolling three-year Local RA program.
			Provided additional details of the commitments for Shown resources as years roll forward. Shown local RA capacity is committed for a period of up to three years; No process to decommit a resource except for certain reasons, such as resource retirements or force majeure.
			SDG&E believes its proposal offers a simple approach to meeting the needs of creating a Local Capacity Reduction Compensation Mechanism using transparent and annually refreshed data. SDG&E believes that while a more granular methodology may provide additional precision or "value" to specific resource types and various areas, the potential lack of available data may cause such a methodology to be difficult to implement.

September 1, 2020

CA Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Advice Letter 45-E

Re: Marin Clean Energy's 2021 Energy Efficiency Annual Budget Advice Letter

Pursuant to Decision ("D.") 15-10-028, *Decision Re Energy Efficiency Goals for 2016 and Beyond and Energy Efficiency Rolling Portfolio Mechanics*,[1] D.18-05-041, *Decision Addressing Energy Efficiency Business Plans*,[2] and guidance from the California Public Utilities Commission ("CPUC" or "Commission"), Marin Clean Energy ("MCE") hereby submits it Annual Budget Advice Letter ("ABAL") for Program Year ("PY") 2021 as MCE Advice Letter ("AL") 45-E.

Tier Designation:

This AL has a Tier 2 designation pursuant to Ordering Paragraph ("OP") 4 of D.15-10-028.

Effective Date:

Pursuant to G.O. 96-B, MCE requests that this Tier 2 AL become effective on October 1, 2020, which is 30 calendar days from the date of this filing.

Background

MCE has been administering energy efficiency ("EE") funds under California Public Utilities Code ("Code") Section 381.1(a)-(d) since 2013.[3] The Commission originally restricted MCE's EE programs to serving gaps in Investor Owned Utility ("IOU") programs and hard-to-reach markets.[4] At the time, the Commission acknowledged that these restrictions may cause MCE's portfolio to fail the Total Resource Cost ("TRC") test and thus did not initially impose a minimum cost effectiveness requirement on MCE.[5] In 2014, however, the Commission lifted the restrictions and imposed the same cost effectiveness requirements on community choice aggregators ("CCAs") as IOUs.[6]

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[1] D.15-10-028, Ordering Paragraph ("OP") 4 at p.123.

[2] D.18-05-041, OP 37, 40, 41, 44 at p. 190ff.

[3] To date, MCE is the only community choice aggregator ("CCA") to have requested energy efficiency funding under Code Section 381.1(a)-(d).

[4] D.12-11-015 at pp.45-6.

[5] D.12-11-015 at p. 46.

[6] D.14-01-033 at p. 14; *see also* D.14-10-046 at p. 120.

On January 17, 2017, MCE filed a Business Plan with the Commission that requested authorization to expand MCE's EE portfolio to include additional sectors and programmatic offerings.[7] MCE proposed to offer programs in the following sectors: (1) Residential; (2) Commercial; (3) Industrial; (4) Agricultural; and (5) Workforce Education and Training ("WE&T"). On June 5, 2018, the Commission approved MCE's Business Plan in D.18-05-041.[8]

<u>Purpose</u>

The purpose of this AL is to request approval of MCE's proposed EE budget for PY 2021. This AL complies with D.15-10-028 and D.18-05-041, which requires MCE to file an ABAL by September 1, 2020. The ABAL provides information about MCE's approved EE portfolio, including

(1) Budgets;
(2) Energy savings;
(3) Cost effectiveness;
(4) Portfolio and program changes; and
(5) Metrics.

In addition to this information, MCE's 2021 ABAL includes the following attachments:

(1) Attachment 1: Marin Clean Energy Supplemental Budget Showing
(2) Attachment 2: Marin Clean Energy Program Changes Explanation Tables
(3) Attachment 3: Marin Clean Energy Budget and Savings True-up Tables
(4) Attachment 4: Marin Clean Energy CEDARS Filing Submission Receipt

<u>Discussion</u>

(1) Budgets

In D.18-05-041, the Commission approved annual and total funding levels for MCE's EE portfolio for PYs 2018-2025 for each of MCE's proposed sectors.[9] Even though the Commission approved annual and total budgets in the Business Plan Decision, the Commission directed PAs to use the ABAL as an opportunity to adjust their annual budgets "to reflect the 2018-2030 goals adopted in Decision 17-08-025 and the interim greenhouse gas adder adopted in Decision 17-08-022 and other relevant factors to provide a more accurate forecast of expected annual funding levels."[10] The revisions, however, "must not exceed the overall funding amount" authorized in D.18-05-041, which caps PAs' total spending for the period 2018-2025.[11]

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[7] *See* Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan (Application ("A.") 17-01-017) filed January 17, 2017.

[8] D.18-05-041, OP 33 at p. 189.

[9] D.18-05-041 at p. 112. The Commission approved a total budget for MCE of $85,736,000 for PYs 2018-2025. This budget includes allocations for Evaluation Measurement and Verification ("EM &V").

[10] D.18-05-041, OP 43 at pp. 191-92.

[11] D.18-05-041, OP 43 at pp. 191-92.

MCE proposes a 2021 EE portfolio budget of $7.56 million. This budget is based on a bottoms-up savings forecast with portfolio modifications relative to MCE's 2020 portfolio and COVID-19 impacts.

Table 1 provides an overview of MCE's 2021 forecasted portfolio budget, savings, and cost-effectiveness. The net savings, TRC, and Program Administrator Cost ("PAC") forecast values exclude market effects.

Table 1: MCE Forecasted 2021 Budget, Cost-Effectiveness, and Savings (Net)

Sector	**Program Year Budget**	**kWh**	**kW**	**Therms (MM)**
Residential	$2,733,236	6,333,145	59	0.06
Commercial	$3,010,541	5,224,085	273	0.09
Industrial	$871,077	1,359,837	33	0.13
Agriculture	$468,195	863,147	112	0.01
Emerging Tech	$0	n/a	n/a	n/a
Public	$0	n/a	n/a	n/a
Codes and Standards	$0	n/a	n/a	n/a
WE&T	$361,481	n/a	n/a	n/a
Finance	$0	n/a	n/a	n/a
OBF Loan Pool	$0	n/a	n/a	n/a
Subtotal	**$7,444,530**	**13,780,213**	**477**	**0.30**
	MCE Savings Target per PY 2019 ABAL True-up	8,380,475	484	0.55
	% of Savings Target	164%	99%	54%
MCE EM&V	$119,112			
MCE Total 2021 Spending Budget[12]	**$7,563,643**			
Uncommitted and Unspent Carryover Balance[13]	$4,000,000			
MCE Total Budget Request[14]	**$3,563,643**			
Authorized PY Budget Cap (D.18-05-041)	$12,404,000			
Forecast 2021 TRC	**1.08**			
Forecast 2021 PAC	**1.17**			

MCE requests Pacific Gas and Electric Company ("PG&E") provide the 2021 budget request amount, split into electric and gas budgets, to MCE via quarterly transfers as calculated below.

[12] Total proposed program year budget spending, including uncommitted unspent carryover.

[13] The uncommitted and unspent carryover balance reflects the total unspent and uncommitted funds from all previous program years that will be used to offset the 2021 fund transfers. More detail on this number can be found in MCE's CEDARS filing. Because each ABAL is filed in Q3, this unspent uncommitted amount is an estimate for the year in which the ABAL is filed.

[14] The amount of funds to be collected (budget recovery) for the Program Year.

Additionally, MCE requests PG&E transfer a one-time payment of the 2021 EM&V budget of $119,112 to MCE by January 15, 2021.

Table 2: Fund Transfers from PG&E to MCE

Fuel Type		**Quarterly Transfer**
Total Electric Budget	$2,672,734	$668,183
Total Gas Budget[15]	$771,796	$192,949
Subtotal	**$3,444,530**	**$861,133**
EM&V	$119,112	**One-Time Transfer**
Total	**$3,563,643**	**$3,563,643**

In addition to forecasting expenditures for the upcoming PY, D.18-05-041 also requires PAs to provide information in their ABALs on budgets and expenditures for previous program years.[16] Tables 3 and 4 shows MCE's authorized budgets and actual expenditures for each program and sector for the two most recent years.

Table 3: Program Authorized Budgets and Actual Expenditures for Two Most Recent Years

		2018		**2019**	
Program ID	**Program Name**	**Authorized Budget**	**Actual Expenditures**	**Authorized Budget**	**Actual Expenditures**
MCE01	Multifamily	$728,686	$558,107	$1,074,957	$585,858
MCE02	Commercial	$816,745	$617,207	$1,185,725	$643,277
MCE03	Single Family Seasonal Savings	$232,250	$137,360	n/a	n/a
MCE04	Financing	$27,031	$18,524	n/a	n/a
MCE05	Multifamily Direct Install	n/a	n/a	$296,971	$158,936
MCE07	SF Comprehensive	n/a	n/a	$1,965,535	$295,218
MCE08	Single Family Direct Install	n/a	n/a	$419,501	$190,211
MCE10	Industrial	n/a	n/a	$690,423	$113,244
MCE11	Agricultural	n/a	n/a	$766,449	$93,617
MCE16	WE&T	n/a	n/a	$160,000	$0

15 Pursuant to OP 36 of D.18-05-041, gas budgets will be transferred to MCE on a quarterly basis.

16 D.18-05-041, at p. 125.