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

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	**Rulemaking 18-07-006** (filed July 12, 2018)

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO THE ADMINISTRATIVE LAW JUDGE'S RULING ADDING WORKSHOP PRESENTATIONS INTO THE RECORD AND INVITING POST-WORKSHOP COMMENTS

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For: California Community Choice Association

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I. Introduction

The California Community Choice Association ("CalCCA") respectfully submits these comments in response to the Administrative Law Judge's Ruling Adding Workshop Presentations into the Record and Inviting Post-Workshop Comments filed April 12, 2019.

The members of CalCCA are the 19 community choice aggregators ("CCAs") and affiliated cities and counties interested in exploring the opportunities of community choice energy. As local government agencies, local governments, or community groups, we are keenly aware of the needs of our communities for affordable energy and the many intersections of social, economic and energy needs. CalCCA focuses our comments on questions of energy affordability in particular as this represents the area of particular expertise of our members, but we are interested in promoting comprehensive consideration of the affordability of all utility bills jointly.

II. Definitions

1. How can the definition of essential service above be refined?

The definition of essential service levels must be revised to include not just health, comfort and safety, but also levels of utility service needed to support functions fundamental to a household's social and economic participation. As identified in the Affordability Framework (Appendix J)[1] a lack of adequate utility services undermines customers' critical social, economic, and educational participation. Any concept of "essential service quantity" must rest fundamentally on a concept of "essential" that incorporates all functions necessary to facilitate household members' ability to pursue their social, academic, and economic goals without incurring financial hardship. A failure to incorporate these aspects risks undermining the household's ability to pay bills on a sustainable basis.

California's experience has shown sharply how such hardships in turn quickly undermine health, safety, and comfort. For example, as emphasized in the disconnection proceeding R.18-

1 Affordability Definitions, Metrics, and Implementation of Affordability Framework: Background and Questions for Parties, Appendix J, Attachment A, Administrative Law Judge's Ruling Adding Workshop Presentations into the Record and Inviting Post-Workshop Comments (April 12, 2019).

10-005,[2] energy insecurity can lead to job losses, poorer academic performance, and potentially social isolation, while a lack of broadband access is associated with lower graduation rates[3] and difficulties to maintain employment. The loss of these social and economic functions can ultimately drive a loss of health, safety, or comfort and drive social consequences and costs far in excess of the relatively small cost of providing the minimal utility service. While addressing affordability may raise costs for other customers, non-collection of utility bills does also, as do the social and economic consequences of social and economic dislocation.

This more focused concept of essential service must include an assessment of the impacts of shortfalls in utility service on the ability of families and individuals to maintain their own abilities to support themselves. A systematic assessment of the essential services should ideally extend beyond the bare minimum of comfort, health and safety to evaluate the consequences for social and economic participation from shortfalls of utility services.

This concept also is fundamental to understanding affordability in frameworks that incorporate an assessment of essential expenses, such as Teodoro's Affordability Ratio. In both contexts, the evaluation of what is essential is tied to non-discretionary spending above that required to support critical functioning. Therefore, the CalCCA members recommend focusing the scope of the definition of "essential service levels" to include support of agreed-upon essential functions:

> An essential service quantity of utility service is that amount necessary for health, comfort, and, safety as well as to facilitate social, economic and academic participation.

2. Is the definition suitable to all public utility services? Why, why not?

Yes. Each public utility service supports critical social, economic, and health functions, so the basic analysis remains the same. Although how much utility service is required to avoid negative social and economic consequences will vary between different services, all have some base level of utility service below which negative consequences begin to accrue.

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[2] See, e.g., Workshop #3: Improving Energy Access by Reducing and Avoiding Disconnections, Disconnections Proceeding, R.18-07-005.

[3] Council of Economic Advisers (2016) The Digital Divide and Economic Benefits of Broadband Access (cited by Achilles, Appendix H).

3. Is it appropriate to connect the concepts of affordability and essential service?

Unequivocally yes. Both essential service and affordability begin with an assessment of a household's essential needs. In the context of essential services, these needs determine essential service quantities, while the non-utility costs of meeting these needs also define non-discretionary budgets that underlie concepts such as poverty measures (e.g., standard federal poverty guidelines, federal supplemental poverty thresholds, and the California Poverty Measure all feature spending on an essential set of goods and services) or the Affordability Ratio. Without such a linkage in a common understanding of what defines essential service and essential expenses, both risk becoming divorced from the lived experiences of customers and ultimately misinforms policy makers.

4. How can the concept of "substantial hardship" be refined and what data sources could be used to further define the concept?

Customers face hardship when they are unable to afford other essential expenses due to high utility bills. If affordability is assessed in terms of the ability to pay for both essential utility service and essential household needs, any adopted metrics are more likely to ensure that utility bills do not crowd out other critical spending categories or lead to utility disconnection. This approach drives several key conclusions about how to measure affordability.

1. ***Unit of measurement*** - Metrics should be developed at the *meter level*, rather than be assessed by market-level or rate impacts, which may reflect affordability unevenly across households.
2. ***Geographic area*** - Metrics should make use of the available county, zip-code, and census tract level data that exist in order to capture the wide diversity of economic conditions across the state.
3. ***Household data***- should reflect the fact that affordability varies among households depending on expenses and income.
4. ***Consideration of all utility bills*** – The sum of all utility costs should be assessed for their cumulative impacts.

1) Unit of Measurement -Since the actual impacts of utility bills can best be understood in the context of household expenses, affordability measures should be expressly tied to a household's other non-discretionary expenses. Since basic definitions revolve around the ability to pay bills without compromising other essential expenses, the most direct measures should include those costs in relation to income in some form. Thus, household metrics should incorporate non-discretionary expenses in order to determine the degree to which utility costs impinge on non-discretionary spending, following the approach of measures such CPUC's material hardship survey in the 2016 Low Income Needs Assessment or the budget-based analysis of the California Budget & Policy Center.

Such an accounting is superior to utility-specific measures, such as energy burden measures, because the simple ratios do not account for what other essential expenses exist and thus are more likely to fail to capture actual hardship. This can become a serious issue with measures that adopt a fixed ratio, because the discretionary proportion of a household budget does not vary in a linear fashion with income. In particular, housing costs are exceptionally high in California, which means lower percentages are more appropriate generally in California than those based on the experience in other jurisdictions and that the appropriate ratio will differ sharply across the state.

2) Geographic Area - Geographic indexing is critical, since essentials, such as food, housing, medical needs, or child care as well as aggregate utility costs, can vary dramatically across the state. Thus, geographic-based approaches may do a better job of more precisely capturing substantial hardship by sub-state geographies and by demographic groups, provided the data include not just climate, but also variation in housing costs, food costs and other essential costs. While this increases the need for data to derive affordability metrics, there are several existing sources, such as those underlying the California Poverty Measure or the American Community Survey. County social services agencies are also a source of aggregate data on household expenses for low income residents.

3) Household data **-** Affordability measures must ideally include household size (e.g., the number of dependents, their age, and the number of income-earning adults), household type (e.g., single parent, two-parent, retiree, etc.) and other measures that can refine the understanding of essential expenses. Each of these variables have substantial impacts on the level of essential expenses. Various existing state data (such as those used to calculate the California Poverty Measure, or the BLS Consumer Expenditure Survey) can provide a useful basis for estimating essential costs.

Several workshop presentations emphasized that affordability occurs on a continuum, so metrics should capture the diversity of the income distribution. For example, the AR_{20} measure is designed to capture the impact low income households specifically (at the 20^{th}percentile). However, to the extent that rates are discontinuous across the income spectrum (e.g, CARE rates are available only below certain income thresholds, such that affordability measures may be sharply different above and below eligibility thresholds.), the Commission should assess affordability impacts at several points in the income distribution, especially around rate discontinuities.

4) Consideration of all utility bills - Since utility costs are defined as essential, the affordability of any single utility type should not be assessed in isolation. While different utility services may be easier to shape to address affordability the impacts on household costs are felt jointly. Thus, the measurement of affordability and efforts to address it should include joint consideration of all utility bills with each sector assigned a percentage of the "utility costs."

II. Utility Metrics

A. General framework

CalCCA recommends applying the following methodology or selection criteria to the Commission's process for choosing affordability metrics. The metrics adopted in this proceeding, collectively or by themselves, should:

- **Reflect regional variation in income**. Metrics must capture sub-state level differences in income in order to avoid obscuring impacts to customers whose incomes are low relative to the essential expenses in high-cost areas.
- **Account for the cost of essential non-utility household expenses (e.g., food, housing, child care, transportation), which may vary by region.** Affordability assessments for utility service should reflect ability of customers to pay without compromising the ability

to afford other basic needs. Essential expenses vary both geographically and as a function of household composition.

- **Measure impacts on customers living at lower percentiles of the income distribution.** Impacts on impoverished customers are a key affordability concern that should be measurable by any metric adopted in this proceeding. Notably, in the California context, income alone, especially average or median income, is not a good measures of the impacts on lower income households. Incomes does not reflect the (often high) cost of essential expenses, including housing or the vast disparities in income that occur within communities or across the state.
- **Measure impacts across multiple income ranges.** While impacts on low-income customers are critical to measure, a comprehensive assessment of affordability must also take into account impacts on other income groups.
- **Rely on inputs that are relatively easy to obtain or calculate from public data sources.** Affordability of utility service will need to be addressed frequently if it is to inform the Commission's decision-making regarding cost-causing filings and other utility activities. Metrics should therefore be relatively easy to calculate and update. However, metrics that are easy to calculate but do not accurately assess the ability of households to afford essential needs should be rejected (e.g., energy burden or % median household income).

With these selection criteria in mind, CalCCA has evaluated each of the metrics discussed in the ALJ Ruling as well as three additional metrics. CalCCA's assessment of each of the proposed metrics is summarized in the table below.

CalCCA proposes three additional metrics be considered. First, as an alternative to a statewide % Median Household Income metric, CalCCA proposes at least an improvement to capture geographical differences by calculating the percentage of median households by region, county, or zip-codes. Since California has dramatic difference in incomes across the state, this "% Area Median Income" measure would scale to the local income distributions rather than a statewide average. The second measure, "% California Poverty Measure," ("CPM") would capture both geographic variation and have some linkage to essential expenses. By leveraging the county-level estimates of essential spending to establish local poverty guidelines in the CPM, the % CPM measure would assess utility bills as a fraction of a regional cost-of-living adjusted minimum budget. The third measure, an "Approximate Affordability Ratio," would combine these measures and be calculated as utility costs expressed as a percentage of the difference of the 20th percentile of county income and the CPM guideline level for a particular county ($AR_{20} = \frac{utility\ costs}{(county\ 20th\ Percentile\ income - county\ CPM)}$). This metric would be a crude approximation of the actual Affordability Ratio, because the CPM may not reflect the full set of essential expenses the Commission would seek to include, but does include utility costs in the estimate of essential expenses. Ideally, the Commission would improve on this metric

As the table indicates, no single metric meets all the criteria listed above. The Commission should therefore assess affordability across several metrics in order to comprehensively measure impacts on customers. Based on an assessment of each metric against its selection criteria, CalCCA recommends prioritizing the adoption of % Area Median Income, the California Poverty Measure, and the approximate Affordability Ratio in combination. Each of these measures captures a slightly different aspect of affordability (e.g., the % Area Median Income captures general impacts on average customers, the % CPM evaluates impacts at the poverty line, while the Approximate Affordability Ratio may approximate the Affordability Ratio using existing data), so assessing affordability of rates with multiple measures should provide a more nuanced and sophisticated view into the impacts on different demographics. Should these measures agree, the Commission may have more confidence in the determination and where they disagree, the Commission can identify issues for further examination.

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Table I. CalCCA Assessment of Proposed Affordability Metrics

	Selection Criteria				
#		**Regional (i.e., Sub-state level)**	**Accounts for Cost of Essential Expenses**	**Captures Impacts on Range of Incomes**	**Simplicity and data availability**
1	% Median Household Income	No.	No.	No.	Yes.
2	Affordability Ratio	Potentially.	Yes.	Yes.	No.
3	Hours at Minimum Wage	Yes (if at city level)	No.	No.	Yes.
4	Average Household Bill, Rates, and Usage	Yes.	No.	No.	Yes.
CalCCA-Proposed Additions:					
5	% Area Median Income	Yes.	No.	Yes.	Yes.
6	% California Poverty Measure	Yes.	Yes.	No.	Yes.
7	Approximate Affordability Ratio	Yes	Yes	No	Yes

B. Specific Responses

CalCCA specifically addresses the numbered questions below in light of our focus on energy services.

8. Which value of average household consumption of energy – monthly average customer electricity and natural gas usage per household, or tier 1 baseline volume – is most appropriate for considering essential service quantity in the context of affordability and why?

Neither of these metrics adequately captures essential service levels. Essential service metrics must be grounded in the amount of utility service required to meet essential needs, especially for lower income households. This will require a dedicated essential use study be developed because neither the average usage nor baselines are derived from an assessment of essential household needs.

Average household usage fails on multiple levels as an essential service quantity measure. First, usage patterns include both essential and non-essential uses and fails to relate that usage to essential needs. Second, by using an average, this measure has no relationship to the critical percentiles of the income distribution. For example, a small number of high users can skew the average upwards in ways that do not reflect the experience of most residents, and drive too high an estimate of essential utility service quantities. In particularly poor communities in which service is not affordable for many households, this measure might establish a level that is actually below essential levels if many residents are not receiving essential service levels. Finally, the average usage amount approximates levels used by the middle of the income distribution, and may obscure affordability issues for vulnerable populations.

Similarly, the IOU baseline kWh measures are not established based on an assessment of essential needs, although arguably these baselines should be. Thus, baselines may fail to capture actual essential service quantities. For example, many lower income residential customers may have higher essential needs than is estimated in baselines, if they are renters who live in older housing stock and have higher needs because of inefficient buildings or they may have limited ability to control their monthly usage. Tier 1 Baseline quantities may therefore not reflect the essential usage levels of these vulnerable customers, at least absent interventions through energy efficiency programs and other services. (CalCCA also notes that baselines may need to be revised in light of societal changes such as heavier reliance in technology and greater reliance on space cooling during longer hot periods under climate change.)

Ultimately, the only appropriate approach to measuring essential service quantities is to evaluate essential use directly using an essential use study or other similar needs-based utility budget. CalCCA understands this will take time to develop an essential use study, but none of the currently available measures adequately assess the essential service level that is a necessary input of an accurate affordability measure.

9. Should essential service for energy be considered at the individual level, the household level, or some other scale? Why?

Essential service should be evaluated at the household level, as a function of household characteristics. Not only is billing at this level, but since service is provided at the household level (e.g., "meter"), this is also the most meaningful scale for analysis of affordability of utility bills. It is likely overly burdensome and thus unrealistic to calculate essential service at the individual level, and not particularly meaningful because it would be impossible to collect direct usage data. Additionally, larger community or regional scales will fail to capture the relationship between needs and energy use at the household level at which budgets are managed. Furthermore, variations in essential services levels and household essential needs are driven by differences in household characteristics, such as the number of income earners, children, or persons over 65, as well as by building characteristics, such as construction type, bedrooms, age and the ability to reduce their consumption, which may often be limited (e.g., renters, low-income households).

10. Are there other energy values for essential service quantity not listed previously that would be better suited for the purpose of establishing essential service?

At this time, CalCCA is not aware of existing metrics of essential service quantity that would be better-suited to this effort. Since existing measures are inadequate, new approaches will be required. Regardless, whatever measure is used, it must be able to capture cost impacts at lower percentiles (e.g. 20th percentile of household energy use) to better capture affordability in key income segments. CalCCA recommends that this question be revisited after the various IOU Essential Use Studies are underway.

11. Should essential service for the purpose of energy affordability calculation differ by demographic and/or geographic segment? If so, describe and justify a proposed segmentation including relevant data sources and/or analytical results.

Yes. Any measure that will successfully capture affordability concerns for most or all households must consider geographic and demographic segmentation to account for differences in essential service quantities across jurisdictions and regions (e.g. climate zones), as well as to account for differences due to different household compositions. Ideal segmentation would also consider, among other factors, the age of existing housing stock, household types, homeownership, whether the home is all-electric, and square footage. We anticipate that these considerations would necessarily be incorporated in an essential use study.

This variation means there is no single essential service quantity that applies to all households in the state or even in a single community. Given that essential service quantities will occur across a distribution, the choice of affordability benchmarks will almost certainly involve normative decisions about what proportion of households are to receive affordable service.

III. Affordability Metrics

19. Is percent MHI a good metric for an affordability framework? Why or why not?

No. By itself, percent MHI is not a good metric for an affordability framework because it does not reflect regional variation in income levels, fails to assess impacts on poor households, and does not account for the cost of essential expenses. As the Commission recognizes in Attachment J of the ALJ Ruling, MHI has limitations and "can be tailored to incorporate other factors from the California Poverty Measure in the numerator.[4] The CCAs agree that this metric can – and should – be adjusted to incorporate other factors, particularly those that reflect

[4] Ruling at Appendix J, p. 10

household-level affordability impacts. Therefore, CalCCA recommends relying on % Area Median Income ("AMI") and the % California Poverty Measure ("CPM") instead of % MHI.

Metrics must take regional essential expenses into account if they are to appropriately characterize affordability. Data presented by Sara Kimberlin at the January 22 workshop helps illustrate this point. Using the census Supplemental Poverty Measure, which accounts for expenditures on food, clothing, shelter, utilities, and differences in housing costs, California's poverty rate is 19%.[5] This is the highest poverty rate of the 50 states (excluding Washington, D.C.), according to the U.S. Census Bureau. Under the traditional official census measure of poverty, however, California doesn't even make the top ten.[6] This disparity highlights the critical importance of capturing essential expenses in any assessment of affordability.

As noted above, there are several relatively straightforward improvements on % MHI. First, percent of Area Median Income ("AMI") represents one possible improvement, particularly if measured across several income thresholds as described in the response to question 20 below, because it reflects regional variation in income levels. Overall, however, if a percentage of income approach were to be used, a percentage of California Poverty Measure ("CPM") may be the better alternative to a percentage of MHI, because it captures an index of essential expenses at the county level, and accounts for demographic variation. Affordability should also be assessed at the lowest income levels, and the CPM poverty threshold should be used for this purpose. As described in the January 2019 Affordability Workshop presentation by the California Budget and Policy Center, the CPM "accounts for state-specific policy context and demographics," and provides granular information at the region or county level.[7] The combination of state-specific information, adjustment for the cost essential expenses, and sub-state level of granularity makes the CPM a preferable metric.

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[5] Kimberlin, Sara. "Basic Needs and Economic Insecurity in California: Definitions and Data." Presented at Affordability Workshop #1: Defining and Measuring Affordability. January 22, 2019. p. 11.
[6] U.S. Census Bureau. "Supplemental Poverty Measure: 2017." p. 26. Available at https://www.census.gov/content/dam/Census/library/publications/2018/demo/p60-265.pdf
[7] Kimberlin, Sara. "Basic Needs and Economic Insecurity in California: Definitions and Data." Presented at Affordability Workshop #1: Defining and Measuring Affordability. January 22, 2019. p. 14.

CalCCA believes that affordability thresholds are set according to fundamentally normative questions that cannot be addressed by analytics alone – i.e., how much should households reasonably be expected to pay for energy services and/or how many hours a household's earners would need to work at minimum wage? Recognizing that there is no "golden number," CalCCA supports the approach of adopting a threshold as a guideline because addressing affordability ultimately requires an understanding of what costs are unaffordable, based on an understanding of other essential expenses. Of course, the benchmark percent chosen represents a normative determination and would be grounded in estimates of the fraction of income typical low-income households should spend on energy to meet essential needs. However, establishing that threshold is a question that should involve careful discussion with all stakeholders to ensure a just threshold is chosen.

20. Should percent MHI be measured using a single threshold, multiple thresholds, or a continuum? At what value or values should an affordability threshold be set, if any?

Any affordability metric (whether it's MHI, CPM, or AMI) should be measured across multiple thresholds and adjusted for household size (similar to the way income limits are defined for affordable housing), household type, as well as for other household characteristics that may affect essential service. In addition, rates should be evaluated at multiple points in the income distribution, including at median income, at incomes above CARE eligibility levels, at the 20th percentile (commonly used as the boundary of low income), and the poverty line. Similarly, once budgets for essential needs are determined, the Commission would be able to have different benchmarks for different percentiles of the household income distribution as appropriate.

Such an approach of assessing affordability at different thresholds may capture affordability issues that arise because programs such as CARE or FERA are applied in stepwise fashion such that utility rates may be more affordable below certain thresholds where programs apply, but unaffordable at higher income levels that are not eligible for such programs.

21. Should the percent MHI metric be refined to be more sensitive to other essential household expenses? Why or why not?

a. If so, how should the other essential household expenses be incorporated into the metric?

b. What other household expenses should be considered essential (e.g., child care costs, medical expenses, food, etc.)?

Without refinement, the % MHI fails to capture whether utility bills are precluding essential spending and it fails to capture the dynamics of the poorest households, which are of most concern. Therefore, CalCCA recommends that this metric either be refined or replaced to use a measure that does incorporate an assessment of non-discretionary spending, such as the % California Poverty Measure, which accounts for essential household expenses – housing and utilities, food, child care, health care, transportation, taxes, etc. – by county.

IV. Affordability Ratio:

22. Is AR, or a variation of it, a good metric for an affordability framework? Why or why not?

The Affordability Ratio (AR) is a much better metric for measuring affordability because it incorporates both income and costs of essential expenses by household. One challenge with AR, as proposed, is its focus on a single income percentile. But as the Affordability Framework (Appendix J) notes (and discussed below), "affordability could be considered either at a single income percentile (AR_{20}) or several (AR_{10}, AR_{20}, AR_{30}, etc.), representing different measurements of affordability for different economic strata."[8] CalCCA recognizes that the requisite data may not be readily available, but the Commission should strive to adopt a measure that does not have *a priori* methodological shortcomings.

CalCCA recommends the following inputs at the county or sub-county level as data availability permits:

- Price of Basic Service: levels determined by Essential Use Studies

[8] Affordability Definitions, Metrics, and Implementation of Affordability Framework: Background and Questions for Parties (Attachment J), April 12, 2019, p. 12.

- Household Income: Percentiles of Median Household Income from American Communities Survey
- Essential non-utility Household Expenses: Sample budgets from California Budget and Policy Center or from an Essential Use Study. As a proxy, the CPM may be used.

23. How should affordability measured by AR be evaluated?

a. Should affordability be considered at a single income percentile (just AR_{20}) or multiple (AR_{15}, AR_{20}, AR_{30})? What are the advantages and disadvantages of each approach?

As discussed above, evaluating AR at different percentiles would develop a more sophisticated picture of affordability and help the Commission identify issues that may arise as a result of discontinuities in rates and other programs and trends. While the AR may be typically assessed at the 20th percentile because "mainstream assessments of welfare economics…typically identify the 20th percentile as the lower boundary of the middle class,"[9] this ratio would provide valuable insights at other income levels, such as just above CARE eligibility and the median income. While employing a field-standard measure has benefits in comparability, there are additional key segments of the income distribution to which the Commission should give special attention.

b. For each income percentile considered, should there be one threshold of affordability or several tiers? What are the advantages and disadvantages of each approach?

As noted above, affordability thresholds are set according to fundamentally normative questions that cannot be addressed by analytics alone – i.e., how much *should* households reasonably be expected to pay for energy services? Recognizing that there is no "golden number," Teodoro (2018) recommends adopting a 10% threshold as a rule of thumb to frame decision-making. [10] CalCCA supports the approach of adopting a threshold as a guideline after

[9] Teodoro, M (2018) "Measuring Household Affordability for Water and Sewer Utilities". J. Am. Water 110: 13-24, at p.15
[10] Teodoro, M (2018) "Measuring Household Affordability for Water and Sewer Utilities". J. Am. Water 110: 13-24, at p.21

consultation with stakeholders, because addressing affordability ultimately requires an understanding of what costs are *un*affordable, based on an understanding of other essential costs.

24. How should "essential non-utility household expenses" be defined? What components should be included?

a. Are the sample budgets from the California Budget and Policy Center's "Making Ends Meet" report good proxies for non-utility household expenses? Why or why not?

b. What other sources of data could inform the input of non-utility household expenses?

The sample budgets from the California Budget and Policy Center are good proxies for "essential non-utility household expenses," and presumably Essential Use Studies would develop additional sophisticated analyses. CalCCA agrees with the way the household budget components are defined in the CBCP study. (However, CalCCA notes that the cost of housing and utilities are currently combined in the sample budgets and must therefore be separated in order to determine "non-utility" essential expenses.) CalCCA strongly supports the inclusion of, at least, housing costs in the measurement of essential expenses.

25. Is there a different variation of AR or way to evaluate AR that would better indicate affordability?

As discussed above, the fundamental concept of the AR is sound in that it expressly looks at income less essential expenses but the concept should be expanded to examine particular geographic variations and a broader range of income segments.

26. What should an appropriate AR value (or values) for affordability be? How should it (or they) be determined?

CalCCA supports the Teodoro paper's suggestion to adopt an AR_{20} value of no more than 10% as one benchmark among several to assess overall affordability. But as we note above, affordability thresholds are set according to fundamentally normative questions that cannot be addressed by analytics alone – i.e., how much should households reasonably be expected to pay for energy services? Recognizing that there is no "golden number," CalCCA supports the approach of adopting thresholds as guidelines.

V. Hours at Minimum Wage:

27. Is HM a good metric for an affordability framework? Why or why not?

Hours at minimum wage ("HM") is a modestly helpful metric for understanding impacts on low-income customers, since it "represents the cost of basic water and sewer service for low-income households, many of which work at or near minimum wage."[11] However, HM does not provide complete affordability information because it is difficult to place in context. For example, to interpret HM, it is critical to understand whether households have other costs that render a particular HM affordable or unaffordable, such as housing costs, child care, food, transportation, and so forth. Furthermore, since many households may not earn net minimum wage (e.g. workers dependent on tip income or those with significant work expenses), HM alone may miss important dynamics among low income households. This absence of context makes the metric less useful than others considered here. Regardless of these other considerations, establishing a threshold is also a normative decision what amount of work is acceptable to devote to utility service. This decision will require careful discussion and consideration with stakeholders.

28. Should HM be used by itself or in combination with another affordability metric? Why or why not?

If explored further, HM may be useful in combination with other metrics. As stated above, income alone, including income at minimum wage, may not be a good indicator of poverty in highly expensive areas. Metrics that provide a regional assessment of household's expenses (such as CPM or AR) will provide a more complete picture of impacts.

[11] Teodoro, Manuel P. "Measuring Household Affordability for Water and Sewer Utilities." Journal AWWA. January 2018. p.16

29. What is an appropriate HM value to indicate affordability?

Prof. Teodoro's presentation at the January 22 workshop recommended that HM be less than or equal to approximately 8 hours.[12] However, whether households can afford to dedicate 8 hours of wages to utility costs depends on what other costs the household has. As noted elsewhere, establishing a threshold is inherently normative. That said, should HM be a preferred metric, it must be modified to incorporate, or be used in tandem with, other metrics that address sub-state differences and include basic needs.

CalCCA feels that staff resources should be preferentially devoted to other measures first.

VI. Average Monthly Household Bill, Rates, and Service Usage

30. Are the average monthly household bill, rates, and service usage appropriate proxies for measuring household-level burden, rate impacts, and cumulative impacts of rate requests and programs across proceedings and industries?

No. Average monthly household bills miss most of the critical drivers of affordability: geographic variation, total essential household expenses, and focus on key vulnerable segments. Thus, average bills, rates and usage fail to capture the critical dimensions of affordability.

a. Are there additional metrics that should be added to this group?

Affordability ratio and % CPM both do a better job of capturing key drivers of affordability.

b. Should any be removed?

Since these are less informative than many other measures, it is unclear what value they provide or why these measures would be retained.

c. Do these metrics translate well between energy, water, and telecommunications industries?

In principle, the metrics of affordability should translate between all utilities that provide essential services required to meet essential needs. By the same token, the metrics that fail to

[12] Teodoro, Manuel P. "Affordability: Meaning and Measurement." Presented at Affordability Workshop #1: Defining and Measuring Affordability. January 22, 2019. p.16.

capture critical aspects of affordability for energy will also fail to capture critical aspects of affordability for other services.

31. Would displaying average monthly household bill, rates, and service usage by geographical region, zip code, or political boundaries provide more insight into affordability?

Subject to the caveat that these measures do not capture the key dynamic of household essential spending, geographically segmented measures could provide insights into where there are particular affordability concerns if, for example, particular zip codes have especially high averages.

32. How can these metrics complement or add value to metrics such as AR_{20} or Energy Burden?

They may identify locations where additional data collection should be focused.

VII. Implementation of an Affordability Framework

34. Assuming affordability should be assessed over a certain time period to account for the cumulative effects of multiple rate changes, what should the period be or how should it be determined?

CalCCA agrees with the Framework (Attachment J) that, "a given rate change's impact on affordability should be analyzed as part of the justification that the rate change in question is just and reasonable." To that end, CalCCA also agrees that an assessment of proposed rate change impacts on affordability should be conducted in each filing or proceeding that would result in rate changes.[13] CalCCA is also mindful that assessing the cumulative impacts of multiple changes quickly becomes extremely complex, but this level of granularity will help define which factors are most critical.

CalCCA urges the Commission to consider an individual proceeding's impacts on affordability in the context of a comprehensive understanding of the cumulative impact of

[13] Affordability Definitions, Metrics, and Implementation of Affordability Framework: Background and Questions for Parties (Attachment J), April 12, 2019, p. 17.

current, pending and planned rate changes (across proceedings and industries) on a customer's bill. As noted in the Public Advocates Office April 24 presentation to the Commission's Emerging Trends Committee, seemingly minor revenue increases, which are often reflected in system average rates, can have larger impacts on some customers, such as baseline rate increases that have well exceeded inflation.[14] These individual proceedings' revenue increases have cumulative impacts on customer bills.

Determining the significance of small changes that add up to a cumulatively significant impact requires a sophisticated assessment of each change in context. The key information the Commission will need to determine the relative impact of each change compared to all others would be to have a measure of the relative impact of each decision. The Commission would then be in a position to evaluate which relatively large impacts are worth pursuing and which may not be.

In accord with the Public Advocates Office April 24 presentation, CalCCA recommends a ten-year time period for the evaluation of impacts from individual decisions. While the later years in a ten-year "look-ahead" may not be dispositive, they can provide the Commission and stakeholders a longer-term view on affordability.

35. **What level of demographic and geographic segmentation of the residential customer population do the metrics need to consider to "comprehensively assess the impacts on affordability of individual Commission proceedings considering utility rate changes"?**
    a. **Is a county-by-county analysis sufficient? If not, how should sub-county and other demographic segments be determined?**

While the ultimate metrics, demographic segmentations, and geographic segmentations the Commission adopts will be subject to the practicalities of available data and feasibility, the Commission should maintain its intention "to reflect the cumulative bill impacts since a

[14] Rate Trends 2009-2019, Public Advocates Office presentation at the Commission's Emerging Trends Committee, April 24, 2019, http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Cal%20Advocates%20Rate%20Trend%20Presentation%20-%20April%2024th%202019.pdf.

customer often pays for electricity, gas, water, and telecommunications services under a single household budget."[15]

While much data is available at the county level, CalCCA appreciates the need to examine residential customers at the sub-county level. California is home to the largest and most populous counties in the country—San Bernardino has over 20,000 square miles, and more than 10 million people live in Los Angeles County. Where available, zip-code and/or census-tract geographic segmentation of residential customers demographic data should be used. Thus, county level geographic segmentation is probably a sensible approach given existing data at that level, but it may prove that the zip code or census tract level data is rich enough to support the desired analyses. Ultimately, this choice will turn on the available data and whether the error associated with the inherently smaller sample sizes at the zip code and census tract level will render the metrics too variable to be useful.

Demographic segmentation provides a similar value because essential household expenses vary considerably depending on the nature of the household. Thus, a better segmented analysis will result in much more accurate assessment of impacts. Thus, demographic data should include at least:

- Household income by household size
- Household type (e.g., single parent family, double parent family, adults, retirees, medical baseline, etc.)
- Area median income
- Median rents by number of bedrooms
- Homeownership
- Food costs by household size
- Child care costs
- Healthcare costs by household size
- Transportation costs by household size

[15] Assigned Commissioner's Scoping Memo and Ruling, November 19, 2018, p. 3.

- Miscellaneous costs by household size that accounts for costs including clothing, personal and household needs and education expenses.

b. What is the best way to apply the affordability framework to other vulnerable populations that may be overlooked by examining only household income?

If the demographic analysis segments incorporate vulnerable segments, the Commission will be in a position to assess the impacts on those segments specifically. However, definition of those vulnerable populations will require careful stakeholder consideration.

36. What other vulnerable populations should be considered within the context of this framework, or how should vulnerable populations be determined?

CalCCA recommends a more thorough discussion among stakeholders on how "vulnerable populations" should be defined. Broadly, the vulnerable populations definition should reflect key household characteristics that heighten the impact of higher utility bills on the household's ability to meet basic household needs. In the Disconnection and De-Energization proceedings definitions of vulnerable populations focus on the impact of losing (electrical) utility service, which is a valuable framework, but neither adequately accounts for the (in)ability to pay for such service. In this context, vulnerability should probably refer to households that are vulnerable to inability to pay and vulnerability to severe impacts if the power is disconnected (and reconnected with attendant fees).

For residential customers with vulnerable populations, the affordability frameworks should reflect the key household characteristics that heighten the impact of utility bills. The Commission may wish to consider vulnerable populations to include, in part:

- Households on medical baseline, which may have higher electricity usage and greater medical needs/expenses, that are different from "regular" households.
- Households headed by a single parent (e.g. female headed household with two children) may have limited incomes and greater expenses as compared to a three-person household with two adults and one child.

- Households with a member that is disabled, which may have higher medical expenses and/or limitations on the ability to earn income.
- Households with a larger share of residents over 65 years of age may have fixed incomes.

VIII. Conclusion

CalCCA appreciates the opportunity to participate in this critical discussion and looks forward to playing a constructive role as the Commission seeks to address the questions of affordability that are critical to the well-being of the state.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	Rulemaking 18-07-006 (Filed July 12, 2018)

REPLY COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO THE ADMINISTRATIVE LAW JUDGE'S RULING ADDING WORKSHOP PRESENTATIONS INTO THE RECORD AND INVITING POST-WORKSHOP COMMENTS

CALCCA
ADVANCING LOCAL ENERGY CHOICE

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June 4, 2019

I. Introduction

Pursuant to the *Administrative Law Judge's Ruling Adding Workshop Presentations into the Record and Inviting Post-Workshop Comments,* issued April 12, 2019 ("ALJ Ruling"), CalCCA submits this reply to opening comments. On May 13, 2019, CalCCA and several parties filed opening comments on the April 12 ruling. On May 10, 2019, the ALJ issued *E-Mail Ruling Granting Extension of Time to File Post-Workshop Reply Comments*, which granted an extension of time until June 4, 2019 to submit replies. Pursuant to the May 10 ruling, these comments are timely filed.

CalCCA addresses the following issues in its reply:

A. Affordability Ratio and percentage-of-income based metrics are preferred over others.
B. Adopted affordability metrics should incorporate both costs and ability to pay.
C. Energy providers can and should leverage available datasets.
D. An improved measure of 'substantial hardship' should be adopted.

CalCCA addresses these topics in more detail below.

II. Discussion

A. Affordability Ratio and percentage-of-income based metrics, with some modifications, are best suited to measure affordability.

As stated in opening comments, CalCCA recommends prioritizing the adoption of three metrics to address issues raised by other parties in their comments: percentage of Area Median Income ("% AMI"), percentage of California Poverty Measure ("% CPM"), and a variation on the Affordability Ratio ("AR") calculation, referred to in opening comments by CalCCA as an "Approximate Affordability Ratio".[1] CalCCA recommends that the Commission adopt % AMI and % CPM in place of percent MHI. CalCCA also recommends adjusting the standard AR calculation to include the California Budget and Policy Center's county-level estimates for essential expenses, developed for its "Making Ends Meet" study, as inputs in the denominator.[2] CalCCA further clarifies its proposal for "Approximate Affordability Ratio" here:

[1] CalCCA Opening Comments on Workshop at p. 8.
[2] See "Basic Needs and Economic Insecurity in California: Definitions and Data." Presented by Sara Kimberlin at Affordability Workshop #1: Defining and Measuring Affordability. January 22, 2019. p. 17-25.

$$AR_{20} = \frac{(Household\ Size)\ x\ (Cost\ of\ Essential\ Utility\ Services\ per\ Capita)}{(County\ 20th\ Percentile\ income - county\ level\ Family\ Budget\ Estimates)}.$$

Many parties noted the shortcomings of % MHI in their opening comments.[3] PG&E commented that % MHI is not an appropriate metric because it does not "factor in the different costs of living in California."[4] Similarly, UCAN asserts, "Because housing costs in California are so burdensome for low-to-moderate income Californians who live in coastal areas, if the Commission decides to use MHI as a metric for determining the affordability of utility services, it should include [a] housing factor that is tied to the cost of renting a 1-2 bedroom home or apartment."[5] CWA agrees, noting that metrics "must be tailored in a manner to reflect the circumstances in particular locales in a more granular fashion."[6] CalCCA agrees. Instead of % MHI, metrics that better account for regional variations in income – such as % AMI – and that reflect costs of essential expenses – such as % CPM – should be used.

Additionally, CalCCA agrees with the Public Advocates Office that if % MHI is adopted, it should represent low-income customers and be calculated using the first (or first and second) income quartiles."[7] A further improvement upon the Public Advocates Office suggestion would be to assess affordability impacts on low-income customers based on the CPM income threshold for poverty.

Many parties support the use of the Affordability Ratio.[8] However, as parties also note, inputs to the metric can be cumbersome or difficult to find. In particular, as UCAN cites in Appendix J of the April 12 ALJ Ruling, "… there is no universal definition of what expenses are essential and should be included in the denominator."[9] CalCCA believes that this drawback to the AR calculation can be largely overcome if essential expenses from the California Budget and Policy Center's basic family budgets from the Making Ends Meet Study are used as proxies for "essential expenses" in the denominator. The use of this information would also meet the Public

[3] CalCCA, PG&E, UCAN, CWA and TURN
[4] PG&E Opening Comments on Workshop at p. 4.
[5] UCAN Opening Comments on Workshop at p. 18.
[6] CWA Opening Comments on Workshop at p. 4.
[7] Public Advocates Office Opening Comments on Workshop at p. 34.
[8] See Opening Comments from CalCCA, NDC, TURN, and UCAN.
[9] UCAN Opening Comments on Workshop at p. 19.

Advocates Office suggestion that inputs to the metric be "sufficiently transparent [such that] users are able to validate the input data, assess trends in the input factors, and clearly trace movement in the overall metric to changes in the various inputs," [10] because the California Budget & Policy Center study is publicly available.

B. Affordability definitions and metrics should incorporate both utility costs and customers' ability to pay.

CalCCA disagrees with PG&E, SCE, and SDG&E's assessment that Energy Burden is a useful measure of affordability in this proceeding. Inputs to the Energy Burden metric include only income and utility bills. While CalCCA appreciates that this metric is simple to calculate, the Energy Burden metric should be rejected from consideration because (1) it fails to account for regional non-utility household essential expenses, and (2) it relies on income alone, which is not a reliable indicator of customers' ability to afford basic service. In short, Energy Burden does not adequately measure hardship, which is a key component of the definition currently contemplated in this proceeding.[11] The implication of this definitional focus on hardship is that a more holistic understanding of the expenses faced by customers is needed. Indeed, metrics like Energy Burden do not adequately track "hardship" because they offer no insight into a customer's ability to pay their utility bills *and* still afford other essential expenses necessary to maintain their quality of life. As SCE notes, "While Energy Burden is easy to apply to different populations, it is overly simplistic and has serious shortcomings: namely, it does not reflect customers' actual difficulty in paying the utility bill."[12]

C. LSEs can and should leverage available demographic and socioeconomic data.

PG&E and SDG&E express opposition to collecting customer demographics and/or income information. For example, PG&E argues that "utilities do not and should not be required

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[10] Public Advocates Office at p. 34.

[11] The definition proposed in the ruling reads as follows: "A household's total utility costs are affordable if the household can regularly pay for an essential quantity of service of each utility on a full and timely basis without substantial hardship. A bill is more affordable if it reduces the hardship caused by paying for essential utility service." See Attachment J at p. 4.

[12] SCE Opening Comments on Workshop at p. 11

to collect information relating to the disposable income information of our customers."[13] Similarly, SDG&E states that metrics such as Affordability Ratio "present greater data challenges that may not produce comparable added value when compared to % MHI or Hours at Minimum Wage…".[14] CalCCA believes it is in the public interest to go beyond broad metrics like % MHI and Energy Burden and that load-serving entities ("LSEs") should instead do our best to understand the affordability impacts of rates on households in various demographic and socioeconomic segments. The aim is not to track information on the individual customer,[15] but rather to leverage existing datasets to develop an aggregate picture of our communities. As CalCCA noted in opening comments on the OIR, demographic information is readily available if customers are grouped into existing political jurisdictions or economic areas.[16] For example, CCAs have relied on data on poverty levels, linguistic isolation, and unemployment by census tract contained in the CalEnviroScreen dataset, used in combination with internal data, to develop a nuanced view of disadvantaged communities. EBCE has, for example, used geocoding to merge CalEnviroScreen census tract-level information with zip code-level data on CARE enrollment for the purpose of identifying census tracts with large numbers of customers who may face affordability challenges. Other energy providers could undertake a similar exercise.

Additionally, PG&E's claim that utilities do not have information related to customers' income levels is false, as demonstrated by their administration of income-qualifying programs, as well as the practices of other utilities in California. For example, SCE recently shared an analysis of the relationship between customer income ranges and disconnection rates during the April 19 Commission workshop on CARE restructuring. This suggests that utilities may already have information on customers' income.[17] Additionally, data sources like the California Budget and Policy Center's basic family budgets can be combined with income information to estimate disposable income.

[13] PG&E Opening Comments at Attachment A, p. 5.
[14] SDG&E Opening Comments on Workshop at p. 14.
[15] For example, Center for Accessible Technology notes, "the impossibility of making individualized assessments for each customer or household" p. 1.
[16] CalCCA Opening Comments on OIR at p. 2.
[17] See "Joint Status Report on Development of CARE Restructuring Consensus Proposals," Attachment A, "CARE Workshop Report & Status Report on Consensus Proposals", filed April 19, 2019 in R.12-06-013, at p. 3.

Identifying communities where customers are likely to have difficulty making ends meet will be key to solving the affordability challenge. Improving our understanding of customer demographics will not only help measure affordability impacts but also help direct resources and customer programs to those in need.

D. 'Substantial hardship' should be measured consistently with the Disadvantaged Communities Advisory Group's Equity Framework.

The definition of affordability proposed in this proceeding should include a broader concept of "substantial hardship" that encompasses impacts to disadvantaged communities. The Greenlining Institute and GRID Alternatives recommend that the Commission specify the concept of "substantial hardship" such that it reflects the definition of disadvantaged communities used within the Disadvantaged Communities Advisory Group's Equity Framework. CalCCA supports the use of this DAC definition, particularly because it includes areas where income levels are less than 80% of Area Median Income, and thus reflects regional differences in earnings.[18] Additionally, CalCCA believes that this definition could be further improved by including census tracts within the top 25% for poverty, as measured either by CalEnviroScreen's "poverty" column, or with household income levels below the CPM poverty thresholds by county. CalCCA notes that this approach of using multiple qualifying criteria to ensure that the full range of vulnerable communities is identified is similar to the approach used in the Disadvantaged Communities Green Tariff and Community Solar Green Tariff programs.[19]

III. Conclusion

CalCCA appreciates the opportunity to provide these comments in reply. We believe that the approaches recommended here will result in a more regional and representative assessment of affordability for customers in our communities.

[18] We also recommend that regional social service agencies be consulted to confirm that 80% AMI is adequate to meet basic living expenses.
[19] See, Resolution E-4999 (May 30, 2019).

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

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

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

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

Pursuant to the instructions set forth in the *Order Instituting Rulemaking* ("OIR") issued on March 21, 2019, California Community Choice Association ("CalCCA") respectfully submits the following comments on the OIR. Pursuant to the schedule set forth in the OIR, these comments are timely filed.

I. INTRODUCTION

A. About CalCCA

CalCCA is the statewide organization of Community Choice Aggregators ("CCAs") providing electric generation service in communities across California. CalCCA's 18 operational members are projected to serve an annual load of approximately 43,900 GWh in 2019, or about 25 percent of the load of the main three investor-owned utilities ("IOUs"). More than 160 communities across California have elected to participate in CCA programs to meet climate action goals, expand energy options for consumers, ensure local transparency and accountability, and drive the creation of green jobs and economic development. CCAs are committed to providing clean, reliable electric service at affordable rates.

B. Background

In 2018, California enacted Senate Bill ("SB") 237. This legislation has two key elements at issue in this proceeding: (1) the expansion of the Direct Access ("DA") cap by 4,000 GWh as contemplated in Public Utilities Code Section 365.1(e),[1] and (2) the development of a recommendation to the legislature by the California Public Utilities Commission ("CPUC" or "Commission") regarding further DA expansion as contemplated in Section 365.1("f"). [2]

The foundations and policy reasons supporting direct access have fundamentally changed since the original opening of California retail markets to DA service. The original idea of opening the market to direct access was purely one of deregulation and to "place sustainable, downward pressure on the cost of electricity to all classes of California ratepayers." [3] Now the Commission has an increased focus on greenhouse gas emission ("GHG") reductions, increases in the use of renewables and a focus on reliability.

As demonstrated in various filings at the Commission showing CCAs are leaders in aggressive decarbonization and maintaining affordable rates, CalCCA supports focusing on affordability, reliability and decarbonization. Accordingly, the Commission should consider these policy directives as it evaluates changes necessary to current DA rules for the DA expansion contemplated in Section 365.1(e) as well as consideration of any future expansion of DA based on legislative action taking place after submission of the report required in Section 365.1("f"). The California electricity system is undergoing a transformational change, including the increase of

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[1] All section references are to the Public Utilities Code unless otherwise noted.
[2] Due to a typographical error in the statute, there are two subsections (e) in Section 365.1; for clarity purposes, we refer to the second of these subsections as ("f").
[3] Decision ("D.")95-12-063 as modified by D.96-01-009, at 2.

renewables resulting in an increased need and focus on reliability, the growth of CCA and the initiation of PG&E bankruptcy proceedings.

C. CalCCA's Recommendations

In these comments, CalCCA respectfully requests that in Phase 1 of this proceeding the Commission:

- create a fair not-to-exceed allocation of DA for each CCA to avoid disparate impacts on any one entity;
- implement a corollary to Resolution E-4907 for the timing of departures to DA to allow for adequate planning and prevent cost-shifting;
- order the IOUs to provide each CCA with access to the DA waitlist to ensure that CCAs can equally plan for load departures; and
- consistent with requests CCAs have received from DA customers in their territory, allow DA customers in limited circumstances to elect to move to CCA service and allow the customer to return to an ESP without needed to return to the waitlist.

CalCCA respectfully requests that in Phase 2 of this proceeding the Commission:

- evaluate the impact of the current DA expansion on deployment of renewable energy resources and reduction of GHGs to inform DA policy; and
- launch a public stakeholder process to discuss the planned Commission report to the legislature contemplated in Section 365.1("f").

CalCCA requests that the Phase 1 issues be addressed within the proceeding's planned workshop.

II. CATEGORY AND NEED FOR HEARING

CalCCA supports the determination that this proceeding is quasi-legislative. CalCCA expects to be able to address many issues through comments and at least one workshop, however, hearings may be needed in this proceeding regarding:

- Determining appropriate allocations of DA across IOU footprints and Load Serving Entities ("LSEs");
- Evaluating expected disparate impacts on certain CCAs;
- Evaluating the cost-shifting impacts of the OIR's staff proposal as it relates to the timing of departures of load; and
- Determining the renewables and GHG impact of DA departures.

III. COMMENTS ON THE ORDER INSTITUTING RULEMAKING

The OIR sets forth a series of questions regarding the implementation of DA expansion. CalCCA's responses are set forth below.

A. How should the Commission implement Section 365.1(e) of SB 237?

1. *Whether the Commission should adopt Staff's proposal ["Staff Proposal"], noted below, or a different approach.*

a. *Staff's proposal: The 4,000 GWh is apportioned as a percentage of the load for the full service territory of an IOU, excluding residential and existing Direct Access load, irrespective of which load serving entity currently serves the remaining load.*

CCAs cannot adequately evaluate the Staff Proposal without additional information. In the absence of detailed waitlist information, CalCCA recommends using an existing waitlist and setting the selected waitlist as the load eligible to depart under the current expansion, up to a set maximum per CCA. This is described in greater detail below.

The most fundamental piece of information is the DA waitlist. As further discussed in paragraph 1.c. below, CCAs need this information on the DA waitlist pertinent to their service areas *now* in order to model and plan for expected DA departures – this must include customer-specific information. CalCCA asks the Commission to order each IOU to provide each CCA with the DA waitlist on a confidential basis in order for each CCA to adequately assess the staff proposal and evaluate any alternative proposals. Without customer-specific information, CCAs cannot adequately plan for procurement or rate-setting due to the variety of sizes and types of potential DA customers, or their priority on the DA waitlist. This impacts not only load, but load shape and allocation of customers across CCA rate classes.

CalCCA also requests a consistent data baseline from the Commission, specifically the data the Commission would be using in Tables 1 and 2 below. It would benefit all parties to be working from the same figures as the Commission.

With regards to the apportionment process itself, the expansion set forth in Section 365.1(e) is more complicated than the Staff Proposal reflects. There are three steps to apportioning the DA expansion contemplated under SB 237. First, the Commission needs to determine the overall DA allowance by IOU. Second, the Commission needs to subtract out existing and reserved DA loads. Third, the Commission should protect against a disparate impact on any one CCA.

Step One: Define the Total DA Load Cap by IOU

The first step the Commission must take, consistent with D.10-03-022, is to identify the total DA load allowance.

Table 1. Authorized Direct Access Cap (in GWh)
Within Service Territories of the Electric Utilities

Line		SCE	PG&E	SDG&E	Statewide
1	SB 695 Allowance	11,710	9,520	3,562	24,792
2	SB 237 Allowance				4,000
3	Total Load Allowance				28,792

Line 1 is taken from D.10-03-022 at 7 and defines the total amount of DA allowed after the SB 695 expansion. Line 2 is the 4,000 GWh increase allowed under SB 237. Line 3 is the sum of Line 1 plus Line 2.

Step Two: Define the Available DA by Subtracting Existing and Reserved DA

Once the authorized DA cap is defined, then the Commission defines the new DA load allowance.[4]

Table 2. New DA Load Allowance (in GWh)
Within Service Territories of the Electric Utilities

Line		SCE	PG&E	SDG&E	Total
1	New Total Load Cap				28,792
2	Existing DA				
3	Reserved DA				
4	New DA Load Allowance (Line 1 less Line 2 less Line 3)				

Line 1 is the same as Line 3 of Table 1. Line 2 is existing DA for 2018. Line 3 is reserved DA for 2019. Line 4 is then the new DA load allowance.

Step Three: Prevent Disparate Impacts on Individual CCAs

Once the new DA load allowance has been determined, CalCCA proposes that the Commission protect against an allocation of the 4,000 GWh on any one CCA in excess of its fair share. This is to ensure that CCAs also do not face disparate impacts. As the Commission evaluates

[4] D.10-03-022 at 7

an appropriate allocation of allowable DA departure across IOUs and CCAs, it must take into consideration the significant differences in risk exposure described below.

When the legislature adopted SB 237 and the 4,000 GWh allowance, it envisioned it as an incremental increase in DA – an increase of 2.15% within the IOU footprints.[5] However, the waitlist is not evenly spread across all LSEs. As a result, the current staff proposal to apportion the 4,000 GWh solely on an IOU territory-wide basis could have significant, disparate – and avoidable – impacts on certain CCAs. The amount of load eligible to depart under the DA reopening varies greatly across each CCA, both on a percentage and a load basis. As noted earlier CCAs cannot adequately assess the staff proposal or impacts without additional information. In the absence of the detailed waitlist information and in order to avoid disparate impact on any one CCA, CalCCA recommends that the maximum amount of load able to depart from any one CCA be the lesser of load currently on the existing waitlist, or its fair share of load. This should work hand-in hand with providing information as to who the customers eligible to depart are for the current expansion, namely, those on the selected waitlist.[6]

To give context on an individual CCA basis, over 12% of Silicon Valley Clean Energy's total load and over 6% of East Bay Clean Energy's total load is on the current waitlist. This shows that the waitlist itself is not distributed evenly across LSEs, much less that the waitlist would "clear" evenly across LSEs. These departures can represent a significant volumetric shift for

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[5] "According to the CPUC, the existing DA cap represents about 13.25 percent of the total electric IOU territory load (aggregated for all retail sellers in the IOU territory). This bill would increase the current cap on DA service to 4,000 GWH and apportion those costs to each of the electrical corporations. The 4,000 GWH would increase the cap to about 15.4 percent of the total electric IOU territory load." SB 237 Bill Analysis of the Senate Committee on Energy, Utilities and Communications, August 31, 2019.
http://www.leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB237#
[6] *See* Section a. above.

already projected – and procured-for – load along with potential changes in overall load profile which would impact procurement planning. Other CCAs face similar levels of load departure which jeopardize their ability to successfully manage their operations in a way that results in affordable rates, continued procurement of reliability resources and resources required to be under long term contract while also avoiding discriminatory cost impacts to their remaining customers.[7]

Moreover, the Commission must remember that the IOUs and CCAs are not similarly situated with respect to recuperation of stranded costs that may result from material load departures. Simply stated, the IOUs are guaranteed cost recovery for load departures – via mechanisms such as the Power Charge Indifference Adjustment ("PCIA") and the Cost Allocation Mechanism ("CAM") – and CCAs are not. While the same procurement obligations, including resource adequacy and long-term renewables procurement, are in place for CCAs and IOUs, the impacts on CCAs and IOUs are entirely different.[8]

b. Staff's proposal: To comply with year-ahead Resource Adequacy requirements, and address potential cost-shifting, customers enrolled as a result of the 4,000 GWh expansion will not begin service until January 2020.

CalCCA opposes the timing set forth in the Staff Proposal. The Commission has already determined an approach for load migration to ensure fairness, no cost shifting, and adequate

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[7] The PG&E CCAs have an average of over 55% DA eligible load.

[8] After the energy crisis in the early 2000s, California adopted Assembly Bill ("AB") 57 (2002). This legislation did away with the Commission's after-the-fact reasonableness review of IOU procurement and instead replaced it with guaranteed cost recovery under contracts. (Section 454.5(d)(2).) The "pre-approval" of procurement contracts in lieu of after-the-fact reasonableness review was considered when the Commission subsequently implemented the PCIA methodology in D. 04-12-048. In that decision, the Commission stated: "In general we agree that the utilities should be allowed to recover their stranded costs from all customers, including an exit fee. Such an approach best meets the Commission's goals of providing 'the need for reasonable certainty of rate recovery' (as required under AB 57 and noted in the June 4th Assigned Commissioner Ruling) as well as best ensuring that California meets its energy needs." (Decision 04-12-048 at 57.)

reliability planning. The rationales the Commission used to arrive at the adoption of Resolution E-4907 to manage load departure from IOUs to CCAs are just as salient in the current context. Accordingly, there is no reason to apply different rules for DA expansion, namely allowing DA load to depart after 6 months' notice, compared to allowing CCA load to depart no earlier than after 1 year's notice. In fact, doing so would discriminate between unbundled load served by CCAs and DA providers. Here, the Commission should "incorporate rules that the commission finds to be necessary or convenient in order to… foster fair competition and protect against cross-subsidization paid by ratepayers."[9] The Commission need only modify the timelines set forth in the Resolution to tailor it to DA. Attachment A reflects the current rules applicable to CCAs with a new column for the rules that CalCCA proposes to be applicable to DA customers and ESPs.

c. *Staff's proposal: Eligibility to enroll new Direct Access customers is based off the waitlist that went into effect on January 1, 2019.*

CalCCA cannot opine on the use of the January 1, 2019 waitlist since CalCCA and the CCAs do not have access to it. More than simply being able to analyze the impact of the Staff Proposal, CCAs' access to the waitlist is essential for CCAs to start modelling and planning for expected DA departures *now*. CalCCA requests that the Commission order each IOU to provide each CCA with the DA waitlist on a confidential basis in order for each CCA to adequately plan for its future procurement needs. This complete waitlist is necessary for CCAs to plan for procurement and rate-setting and to mitigate cost impacts to remaining CCA customers.

This access should happen immediately and the list provided to CCAs should be updated on an ongoing basis. CalCCA appreciates the sensitive nature of this information. As such, this information should be confidentially provided to the CCAs so that they can begin to analyze likely

[9] Section 707(a)(4)(A).

impacts from load departure as the proceeding evolves. The IOUs currently maintain the waitlist information based upon their historic position but given the evolution in California's energy markets since the decision was made on who would maintain the waitlist, there is no reason why it should not be allowed to be shared with CCAs who now face higher risk from load departures.

2. Whether there are any timing or process issues related to the increase in Direct Access load and the Commission's rules and regulations for Resource Adequacy, the Integrated Resource Plan, and the Power Charge Indifference Adjustment.

As noted above in these comments, the key timing issue relates to resource adequacy. CalCCA's proposal for this timeline is in Subsection 1.b. above. As the timing issue is resolved for purposes of Resource Adequacy, the transfer of load as accounted for in the Integrated Resource Plans ("IRPs") will also be reflected in a timely manner.[10] There would be no impacts on the PCIA.[11] This is consistent with Section 454.52(d) which states that: "to eliminate redundancy and increase efficiency, [… IRPs] shall incorporate, and not duplicate, any other planning processes of the commission."

3. Whether the Commission must take any additional action to comply with Section 365.1 (e)(2) of SB 237's mandate that "[a]ll residential or non-residential customer accounts that are on [D]irect [A]ccess as of January 1, 2019, remain authorized to participate in direct transactions."

With the expansion of CCA service, a situation has developed that should be addressed as part of the Commission's initial decision in this proceeding. A limited number of DA customers

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[10] It is incumbent upon all LSEs to file their IRPs. To date, all CCAs have provided their IRPs to the Commission and one ESP has failed to do so. See Proposed Decision dated March 18, 2019 in R.16-02-007 at 82.

[11] For example, the PCIA forecast is due each June 1. For a full timeline, *see* Appendix B to Resolution E-4907.

have indicated to their CCA that they would like the opportunity to take unbundled service from their CCA. However, DA customers have raised concerns about their choice being limited. The DA customers have been informed by the IOUs that if they switch to unbundled service provided by their CCA, they will no longer be able to later switch to an ESP without returning to the waitlist. In contrast, DA customers are able to switch between ESPs without limitations on choice or timing. This creates an artificial barrier for unbundled customers and is contrary to the Commission's stated DA policies.

This issue is distinguished from the set-aside of load issue addressed in D.10-03-022. In D.10-03-022, the Commission determined that it would "not grant a special preference or set-aside of load" to customers who had previously received DA service.[12] In that case, none of the customers that were seeking this set-aside were then-current DA customers. Under the current scenario, there are customers currently on DA service that would like to receive service from a CCA without losing its space under the DA cap.

CalCCA recognizes that these situations are limited, and CalCCA is open to further exploring how to address these situations as part of the upcoming workshop. However, consistent with Commission precedent on customer choice and switching, the Commission should affirm in this proceeding that a DA customer may choose to be served by its CCA for the period of its contract time without losing its authorization to later switch between providers. In support of this request and to spur discussion at the upcoming workshop, CalCCA provides the following.

The Commission's overarching policy pronouncement in the context of DA switching is particularly relevant and instructive: "[T]he rules for switching by DA customers should guard against placing any burden on bundled customers, the rules should also promote customer choice

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[12] D.10-03-033 at 22.

and economic efficiency...DA customers should not be unduly constrained from selecting the most economically efficient service option, consistent with avoidance of cost shifting."[13] In the context of switching, there is no practical difference between service from an ESP and service from a CCA. Both are alternative "procurement" or "service" providers to bundled service provided by an IOU.[14] Therefore, a DA customer should not be "unduly constrained" from switching from an ESP to its CCA. Moreover, by applying appropriate limitations, as has been the case under various DA-related circumstances, a customer switching to/from its CCA will not place a burden on bundled customers.[15]

In applying this overarching policy, the Commission has not set distinctions among alternative procurement providers, but rather the Commission has been focused on the following fundamental theme: switching is permissible under various circumstances so long as DA load is not increased.[16] A survey of Commission orders affirms this disposition. In D.02-03-055, the Commission expressed its agreement with the view that "allowing customers unlimited switching between ESPs is consistent with AB 1X since it doesn't increase direct access load."[17] In D.03-04-057, the Commission affirmed this view, but acknowledged that modifications to the switching

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[13] D.03-05-034 at 43.

[14] *See, e.g.,* D.05-12-041 at 39 ("… CCA customers are to be treated like direct access (DA) customers when they switch between procurement providers."). *See also* Resolution E-4946 at 19 ("DA and CCA customers pay generation rates set by their alternative service provider and delivery rates set by [the IOU]").

[15] *See, e.g.,* D.02-03-055 at 22 (describing the Commission's rationale for allowing unlimited switching so long as such switching does not increase DA load). *See also* D.02-03-055 at 22-25 (describing other DA situations in which switching was expressly authorized).

[16] *See* D.04-02-024 at 10 (emphasis added) ("We note the language that was added…established our intent to permit no net increase in load. This was a fundamental theme throughout D.03-04-057.").

[17] D.02-03-055 at 22.

rules are appropriate from time to time to address changing circumstances.[18] In D.04-02-024, the Commission explained its previous reasoning as follows: "the Commission's intent [in D.03-04-057] was to permit relocations and replacements of facilities as long as there is no increase in the total net DA load…."[19]

As evidenced by the numerous petitions and Commission decisions affirming, clarifying and resolving questions about how switching should be applied, modifications are periodically needed to address emerging circumstances.[20] The expansion of CCA service presents another circumstance in which the Commission should clarify how switching should be applied. As it stands now, a DA customer desiring to switch to one procurement provider (its CCA) faces undue constraints and customer choice impediments that are not faced by a DA customer desiring to switch to another procurement provider (an ESP).

CalCCA requests that the Commission address this specific and limited situation as part of the initial decision in this proceeding. To accomplish this, additional clarification will presumably be needed regarding how capacity should be addressed when a DA customer switches to its CCA.

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[18] D.03-04-057 at 13 ("In the interests of fairness, we agree that modifications to D.02-03-055 are appropriate in order to account for normal changes in business operations, provided that there be no resulting net increase in each business customer's DA load."). *See also* D.03-04-057 at 21 ("The modifications sought…would not violate the DA suspension provisions of D.02-03-055 since no net increase in DA load beyond the pre-suspension levels would result.").

[19] D.04-02-024 at 11. *See also,* D.04-07-025 at 41 (affirming that replacement of Direct Access accounts are permitted as long as the customer's total Direct Access load does not exceed contract terms consistent with the Commission's Direct Access suspension decisions); Resolution E-3872 at 7 (allowing transfers of Direct Access load within load limitations provided in the customer's contract); and D.12-12-026 at 14 (referencing the Relocation Affidavit wherein the customer warrants that total Direct Access load as a result of relocation will not exceed the load limitations in the customer's contract).

[20] *See, e.g.,* D.03-04-057, D.04-02-024, D.04-07-025, D.12-12-026, and OIR (Section 3).

These are details that can be addressed in the context of the upcoming workshop and subsequent comments.

4. Any other substantive issues necessary to implement Section 365.1.

In order to best implement Section 365.1, first, CalCCA recommends that the Commission focus on enabling and empowering CCAs – and all parties – to mitigate or avoid stranded costs. Second, the Commission should also focus on ensuring future DA load departures reflect State climate policy and the need for reliability. Third, a Phase 2 must be opened in this docket to ensure a robust public process for developing the Commission's report to the legislature under Section 365.1("f").

a. The Commission should ensure CCAs have the data necessary to mitigate or avoid stranded costs

Much as the IOUs have faced stranded costs as a result of load departures, CCAs will face the same issues. The Commission must allow CCAs the time and opportunity to mitigate those costs impacts. From a stranded cost mitigation perspective, the Commission should ensure that there is sufficient lead time, consistent with Resolution E-4907 for CCAs to adjust their forecasts, update their IRPs, and sell excess procurement in the market.[21] To the extent a CCA has elected to administer energy efficiency programs under Section 381.1(e), those programs would also be impacted because the pool of customers from which such energy efficiency funds are drawn would be reduced.[22]

The ability of CCAs to effectively mitigate costs is based upon transparency and good data. Under the current DA enrollment process, customers interested in taking DA service must submit

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[21] IRPs must ensure that they "minimize impacts on ratepayers' bills." Section 454.52.(a)(1)(D).
[22] Energy efficiency programs under the "apply to administer" framework in Section 381.1(d) would not be impacted.

Six Month Notices to IOUs. CCAs, however, are not notified. The Commission should revise the enrollment process to ensure that CCAs receive notification whenever a customer in a CCA service area submits a Six Month Notice to transfer to DA service. The Commission could take this step immediately, as an interim measure, until a more detailed DA expansion timeline is adopted consistent with Resolution E-4907. As proposed above, CalCCA requests that up-to-date DA waitlists be confidentially provided to CCAs and that consistent processes for load departures be applied to all LSEs. As more information is developed within the docket, other proposals may be necessary to ensure CCA customers are not negatively impacted by load departure to DA.

b. The proposed and future load departures of DA should reflect State climate policy and the need for reliability

The current 4,000 GWh DA expansion as well as any additional future DA expansions should be consistent with current California policies, including Section 365.1("f")(2). In order to prepare its recommendation for the legislature, CalCCA supports evaluating the net impact of the current DA expansion on development of renewables and on GHG emissions. For future DA departures, the Commission may consider prospective evaluation of the GHG impact of a proposed DA transfer or consider limiting CPUC authorization of DA that increases GHG emissions relative to current service levels, such as through the Commission's existing IRP process.

In the Integrated Resources Planning docket, one ESP appears to be in violation of clear statutory directives and decisions requiring all LSEs to file an Integrated Resource Plan. As a matter of basic fairness and nondiscrimination among LSEs, prior to authorizing any expansion of DA based upon SB 237, the Commission must ensure that all current DA providers who are going to participate in the current DA program expansion have met their current legal obligations.

c. The Commission's recommendation regarding future DA reopening should be part of a public process

A public stakeholder process is necessary to discuss and evaluate any further expansion of DA as contemplated in Section 365.1("f"). A separate track of the proceeding should be created to implement an effective public process that provides for meaningful input prior to development of recommendations followed by public review and input of draft recommendations and opportunity for comment by the Parties.

B. With respect to the DACC Petition, the parties may comment on the following:

1. Whether the Direct Access Monthly Report, which IOUs provide to the Commission, should be revised to denote Direct Access load that is reserved and, therefore, not available to assigned to customers who are on the waitlist. Load will be considered as reserved if it is assigned to a customer who has a pending load replacement, load relocation, or account transfer.

CalCCA supports this increased accuracy and transparency on the waitlist reporting. In addition, this report should also indicate space reserved for any DA customer who has chosen to receive CCA service as more fully described in Section III.A.3.a above.

2. Whether Direct Access customers should be permitted to relocate to a new location on the same premises.

CalCCA supports this change, provided that the load is consistent with the load authorized under existing DA rules. Existing DA rules require that the loads of DA customers be consistent with "load changes associated with normal usage variations on direct access accounts."[23] This rule is in place to prevent circumvention of the cap. As such, so long as the loads are consistent with

[23] D.02-03-055 at 19. As a Finding of Fact, the Commission also found: "It is reasonable to interpret a September 20, 2001 date for suspension of direct access to mean that the level of direct access load as of that date (irrespective of whether power had yet flowed under any direct access contract) should not be allowed to increase, apart from normal load fluctuations." D.02-03-055 at 31.

what was authorized for any given customer, DA customers should have the flexibility to relocate or utilize that load as it likes for its business purposes.

IV. SCHEDULE

CalCCA will work with the proposed timeline regarding the current proposed DA expansion pursuant to Section 365.1(e). CalCCA respectfully requests an opportunity to provide post-workshop comments in order to address matters raised within the workshop on the record.

CalCCA also requests a second track of the proceeding to discuss Section 365.1("f"), including all of the key policy issues set forth in Section 365.1("f")(2) in a public process.

V. CONCLUSION

CalCCA thanks Assigned Commissioner Picker and Assigned Administrative Law Judge Powell for the opportunity to provide these comments on the Scoping Memo.

Respectfully submitted,

/s/ Elizabeth Kelly

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April 5, 2019

Attachment A
Proposed DA Expansion Timeline Consistent with Resolution E-4907

Date	CCA Action	DA Customer and ESP Action
Day 1, Year 1 (On or before January 1 Year 1)	(1) The prospective or expanding CCA submits its Implementation Plan to Energy Division and serves it on the R.03-10-003 Service List, on the R.16-02-007 Service List, and on the R.17-09-020 Service List, or successor proceedings.	(1) The prospective DA customer submits its Intent to Take DA Service to Energy Division and to the LSE serving that load.
Day 1 – 10, Year 1	(1) The CPUC notifies the Utility servicing the customers that are proposed for aggregation that an implementation plan initiating their CCA program has been filed.	n/a
Day 1 – 60, Year 1	(1) The CCA provides a draft customer notice to CPUC's Public advisor. (2) Within 15 days of receipt of the draft notice, the Public Advisor shall finalize that notice and send it to the CCA.	n/a
DAY 1 – 90, Year 1	(1) The CPUC sends a letter confirming that it has received the Implementation Plan and certifying that the CCA has satisfied the requirements of an Implementation Plan pursuant to Section 366.2(c)(3). This letter informs the CCA about the cost recovery mechanism as required by P.U. Code Section 366.2(c)(7). If and when the CPUC requests additional information from a CCA, the CCA shall respond to CPUC staff within 10 days, or notify the staff of a date when the information will be available. (2) The CPUC provides the CCA with its findings regarding any cost recovery that must be paid by customers of the CCA in order to	(1) The CPUC sends a letter confirming that it has received the Intent to Take DA Service. This letter informs the ESP about any cost recovery mechanism. If and when the CPUC requests additional information from an ESP, the ESP shall respond to CPUC staff within 10 days, or notify the staff of a date when the information will be available. (2) The CPUC provides the ESP with its findings regarding any cost recovery that must be paid by customers of the CCA in order to prevent cost shifting. (3) The ESP and the Utility should Meet-and-Confer regarding the ESP's ability to conform its operations to the Utility's tariff requirements.

Date	CCA Action	DA Customer and ESP Action
	prevent cost shifting. (P.U. Code Section 366.2 (c) (7).) (3) The CCA and the Utility should Meet-and-Confer regarding the CCA's ability to conform its operations to the Utility's tariff requirements.	
DAY 1 – 90, Year 1	(1) The CCA submits its registration packet to the CPUC, including: a. Signed service agreement with the utility, and b. CCA interim bond of $100,000 or as determined in R.03-10-003	(1) The ESP submits its registration packet to the CPUC, including: a. Signed UDC-ESP service agreement with the utility, b. Completed ESP Registration Application Form, c. Fingerprints are prescribed for required personnel d. Applicable bond amount e. Scheduling coordinator agreement f. ESPs offering electric service to residential or small commercial customers, submit a copy of your Section 394.5 Notice to the Energy Division of the CPUC on or before the date you sign up your first customer or when the first standard service plan filing is due, whichever is earliest
Day 90 – 120, Year 1	(1) If the registration packet is complete, the CPUC confirms Registration as a CCA.	(1) If the registration packet is complete, the CPUC confirms Registration as an ESP.
April, Year 1	(1) The CCA submits its year ahead Resource Adequacy forecast (P.U. Code Section 380)	(1) The ESP submits its year ahead Resource Adequacy forecast (P.U. Code Section 380)
August, Year 1	(1) The CCA submits its updated year-ahead RA forecast	(1) The ESP submits its updated year-ahead RA forecast
October Year 1 (75 days before service commences)	(1) CCAs submit their Monthly load migration forecast for the Resource Adequacy program, filed about 75 days prior to the compliance month.	(1) ESPs submit their Monthly load migration forecast for the Resource Adequacy program, filed about 75 days prior to the compliance month.
Within 60 days of the CCA's or ESP's Commenceme nt of	(1) The CCA shall send its first notice to the prospective customers describing the terms and conditions of the services being offered and the customer's opt-out opportunity prior to	n/a

Date	CCA Action	DA Customer and ESP Action
Customer Automatic Enrollment	commencing its automatic enrollment. (P.U. Code Section 366.2 (c) (13) (A))	
Within 30 days of the CCA's or ESP's Commencement of Customer Automatic Enrollment	(1) The CCA shall send a second notice to the prospective customers describing the terms and conditions of the services being offered and the customer's opt-out opportunity prior to commencing its automatic enrollment. (P.U. Code Section 366.2 (c) (13) (A)) (2) Once notified of a CCA program, the Utility shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process. (P.U. Code Section 366.2 (c)(16))	(1) Once notified of the DA departure, the Utility shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process.
January 1, Year 2	(1) CCA begins service.	(1) ESP begins service.
Following the CCA's or ESP's Automatic Customer Enrollment	(1) The CCA shall inform participating customers for no less than two consecutive billing cycles that: a. They have been automatically enrolled into the CCA program and that each customer has the right to opt out of the CCA program without penalty. (P.U. Code Section 366.2 (c) (13)(A)(i).) b. Terms and conditions of the services being offered. (P.U. Code Section 366.2 (c) (13)(A)(ii).)	n/a

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

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

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

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April 10, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

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

Pursuant to the instructions set forth in the *Order Instituting Rulemaking* ("OIR") issued on March 21, 2019, California Community Choice Association ("CalCCA") respectfully submits the following reply comments on the OIR. Pursuant to the schedule set forth in the OIR, these comments are timely filed.

Based upon the opening comments of the parties and the comments made at the workshop, CalCCA provides the following reply, each more fully discussed below:

Implement a Multi-year Phase-in. CalCCA supports the recommendation of Southern California Edison Company ("SCE") that the Commission should consider a multi-year, phased-in approach to help mitigate issues related to the proposed June 2019 implementation date."[1] Pacific Gas and Electric Company ("PG&E") also considers a multi-year phase in of the 4,000 GWh direct access ("DA") departure.[2]

[1] SCE Opening Comments at 2. PG&E also supports a multi-year approach and states:
[2] "From a customer perspective, it may make sense to parse the new allocation into multi-year phases." PG&E Opening Comments at 4.

Implementation of Processes to Prevent Cost-Shifting. CalCCA supports the PG&E proposal to adopt a process mirroring Resolution E-4907 to ensure no cost shifting.[3] Any proposal that allows for cost-shifting should be denied.

Provide CCAs with Access to Necessary Planning Information. The Alliance for Retail Energy Markets ("AReM") recommended that the Commission "incorporate an additional new step that requires the investor-owned utilities ("IOUs") to provide notice to the Community Choice Aggregator ("CCA") affected when a customer that is currently being served by that CCA affirms back to the IOU that they have elected to participate in the DA program and have been allocated space under the increased DA cap."[4] While CalCCA supports the acknowledgement that CCAs need to have adequate information, the proposal is insufficient. CCAs need additional information including complete access to the waitlist and concurrent information about expected DA load departures when a Notice of Intent is filed.

Increase the Transparency of the Waitlist. The Regents of the University of California ("UC") request that the DA waitlists be made "public on an anonymous basis (e.g. revealing lottery position and associated MWh only)."[5] CalCCA supports this additional transparency and notes that the list provided to each individual load-serving entity ("LSE") should also indicate which accounts that LSE currently serves. The waitlist should be updated and provided as soon as possible after each update to the waitlist.

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[3] "If the Commission is inclined to continue with the proposed approach to begin the expansion of DA service starting in January 2020, PG&E proposes that the Commission adopt a process, on an interim and transitional basis, that mirrors the Resolution E-4907 transition process." PG&E Opening Comments at 4.
[4] AReM Opening Comments at 5.
[5] UC Opening Comments at 4.

Allow for Reasonable DA-CCA Switching. CalCCA has initiated coordination efforts with DA customer groups to clarify an interim DA-CCA Switching approach. Clarification in Phase 1 should be adopted.

Ensuring Consistent PCIA Vintages for Customers. The Direct Access Customer Coalition ("DACC") requests clarification to ensure that PCIA Vintages remain in place for customers that move between DA and CCA. CalCCA supports this approach.

I. WITHOUT COMMON SENSE CHANGES TO TIMING AND PROCESS, CCA CUSTOMERS WILL BEAR UNREASONABLE AND UNNECESSARY RISKS

Without modifications to the Staff Proposal, CCA customers would be asked to bear unreasonable and unnecessary risks due to CCAs' lack of access to relevant information and – as a result – lack of ability to plan for load departures. CalCCA has requested information and procedures to appropriately plan for DA load departures. Appropriate and reasonable planning for load departure will allow CCAs, on behalf of their customers – who now are more than ten million Californians – to minimize any stranded costs from the departure of load to direct access. Such an outcome will benefit all of the remaining CCA customers without any resulting harm to the DA program or existing DA customers. The Commission has repeatedly highlighted that one customer exercising choice should not occur to the detriment of other customers. CalCCA agrees with this foundational policy. Moreover, the opening comments of various parties to this proceeding further highlight this need.[6]

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[6] In its opening comments, CalCCA requested two key elements regarding load departure and planning. First, CalCCA recommended the implementation of the E-4907 process for this 4,000 GWh load Departure. Second, CalCCA requested that "in the absence of the detailed waitlist information and in order to avoid disparate impact on any one CCA, . . . the maximum amount of load able to depart from any one CCA be the lesser of load currently on the existing waitlist, or its fair share of load." CalCCA Opening Comments at 7 (emphasis added).

A. A Maximum "Fair Share" of Load Departures from Any One CCA Is Reasonable and Consistent with Commission Practices

In opening comments and at the workshop, parties have discussed what levels of load departures are reasonable amounts around which LSEs can plan. Commercial Energy in the workshop and Energy Producers and Users Coalition ("EPUC") in their comments referred to the Commission's historical decision to phase in DA in 2% batches.[7] DACC states that a 2% load shift "should easily be accommodated under existing RA program rules."[8] Applying a limit on DA departure from any one CCA equal to 2% under the current 4,000 GWh expansion is reasonable and consistent with this Commission precedent. Without modifications to the Staff Proposal, the impact to any one CCA could be significantly higher. East Bay Community Energy ("EBCE") will address this matter further in its reply comments.

B. The E-4907 Process for the Current Expansion of DA is Appropriate

The parties to this proceeding broadly commented on the waitlist and how this batch of DA departures would be best implemented. The proposals that result in January 2020 departures do not provide enough planning information to CCAs and will result in cost shifting. DACC goes so far as to assert that this cost shifting is acceptable. It is not.[9]

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[7] "In implementing SB 695, the Commission provided for a four-year phase-in of 35% for the first year, up to 70% in the second year, up to 90% in the third year, and up to 100% in the fourth year." EPUC Opening Comments at 3, referencing D.10-03-022. These figures are equal to 2% expansions in DA per batch.

[8] DACC Opening Comments at 6.

[9] "Using the June 2019 lottery to assign the 4,000 GWh expansion to customers will mean that <u>load-serving entities ("LSEs") will not have information on DA switching until the 4th Quarter of 2019</u>. Final RA load forecasts for the 2020 RA compliance year are due by mid-August and LSEs must complete any procurement that is needed to meet their year-ahead RA requirements by October 31. However, the 4,000 GWh expansion represents only about 650 MW to 700 MW of load (depending on the capacity factor of the load switched),[FN] which is less than 2% of the total August peak load for the three IOUs. [FN] Thus, <u>this level of DA switching should be easily accommodated under existing RA program rules</u>." DACC Opening Comments at 6 (emphasis added).

CCA customers – who include low income, medical baseline, small businesses, and nonprofits and community organizations – should not bear any RA costs from the departure of large commercial or industrial customers to DA. Rather, the ESP who is receiving that customer should be responsible for the RA of that customer once the commitment to depart is made.

The DACC proposal highlights CalCCA's concerns about the timing of the departure of the 4,000 GWh of expected DA load. Specifically, a 4th Quarter notification to CCAs of load departures in the 1st Quarter of the upcoming year will prevent CCAs from being able to reflect appropriate changes to resource adequacy ("RA") requirements. CCAs would need to bear the costs associated with stranded RA procurement. Not only is this cost-shifting inappropriate, it is avoidable, contrary to Commission policy, and fundamentally fails to "protect against cross-subsidization paid by ratepayers."[10] Furthermore, CalCCA notes that the "2% of load" will not be allocated evenly across CCAs; it is likely to be concentrated in one or two CCAs' service areas resulting in a disproportionate impact on those CCAs.

PG&E provides analysis supporting CalCCA's position, and "PG&E proposes that the Commission adopt a process, on an interim and transitional basis, that mirrors the Resolution E-4907 transition process."[11] Without this common sense modification, the timing of departures will not align with Commission requirements:

> Given the timing of this OIR, DA providers seeking newly to serve or to increase their DA load in 2020 as a result of the DA expansion will not be able to meet the Commission's requirements to participate in all aspects of the year-ahead RA process, including submitting load forecasts and annual year-ahead filings, prior to serving the newly served or expanded load.[FN] As such, without the DA provider's mandatory participation in all aspects of the year-ahead RA process, and fulfillment of associated system, local, and flexible RA requirements, it will likely be assumed that the departing load will continue to be served by the IOUs or other

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[10] Public Utilities Code Section 707(a)(4)(A).
[11] PG&E Opening Comments at 4.

> incumbent LSEs, who will then have to procure for that load. This potential cost shift and the resulting inequities in RA obligations is exacerbated given the recent adoption of multi-year (three-year forward) local RA requirements beginning with the 2020-2022 RA compliance years in Decision 19-02-022.[12]

Moreover, by implementing the expansion of the 4,000 GWh in January 2020, the Commission does not leave room for error. "SCE notes that the timing of a Commission Order in this proceeding, followed by prompt and accurate load forecast submittals to account for the load migration under this proceeding, ultimately leading to RA compliance requirements for 2020 (as well as 2021 and 2022 for local RA), will be a critical path. <u>Any slip in timing at any step of the process has a significant potential to lead to the allocation of RA requirements and their resulting cost that are inappropriate</u>."[13]

Similarly, San Diego Gas and Electric Company ("SDG&E") notes that: "Until appropriate notice of intent is received from customers expressing their intent to depart bundled load, SDG&E will continue to procure on their behalf to ensure continued system reliability."[14] While procuring on behalf of another entity may work in the case of an IOU which receives cost recovery, this is not an acceptable shifting of costs to CCAs. These outcomes are easily avoidable with modest modifications to the DA program.

Shell Energy North America ("SENA") asserts that: "The expansion of direct access customer load under SB 237 is very different from the formation of a new CCA as discussed in Resolution E-4907. In that Resolution, the Commission established a timeline and process for CCA program implementation, including load forecasting by a CCA to comply with RA requirements."[15] CalCCA notes that Resolution E-4907 applies to all CCA departures. This

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[12] PG&E Opening Comments at 3-4 (emphasis added).
[13] SCE at 5 (emphasis added).
[14] SDG&E Opening Comments at 4.
[15] SENA Opening Comments at 8.

includes new CCA formations and CCA expansions of any size, including departures smaller than the 4,000 GWh proposed to depart to DA in this proceeding.

SCE and PG&E recommend multi-year phase-ins. If the Commission does not implement the proposed Resolution E-4907 process and instead proposes to implement any amount of load by January 2020, CalCCA would support this multi-year approach in order to allow for improved planning and accuracy of RA procurement.

C. Increased Waitlist Transparency Is Needed for Good Resource Planning and Mitigating Potential Cost Shifts

Several parties expressed interest in updating the DA waitlist for the SB 237 expansion. Access by the CCAs to the relevant waitlist information of that CCA's customers is essential. While CalCCA supports additional transparency in aggregated information, that aggregation is not a sufficient substitute for the waitlist. The CCAs are not asking for confidential customer information – these customers are already customers of the CCA. The distribution utility should not have access to a CCA's waitlist while the CCA serving that load and planning for that load does not. Over the longer term, it will be important to revisit the overall structure of the DA program to align development and handling of waitlists and other matters to bring them in to the new paradigm where CCAs serve the majority of load in their service territories. Furthermore, the waitlist should be updated and provided as soon as possible after each update to the waitlist.

Parties acknowledge that more data needs to be provided to CCAs. AReM acknowledged an additional step that is needed to ensure that the waitlist information is provided to CCAs:

> AReM believes that the lottery process will need to incorporate an additional new step that requires the IOUs to provide notice to the Community Choice Aggregator ("CCA") affected when a customer that is currently being served by that CCA affirms back to the IOU that they have elected to participate in the DA program and have been allocated space under the increased DA cap. This new step is critical in

> the RA process so that the impacted CCA is aware of its migrating customers and can adjust its forecasts and its resource procurement accordingly.[16]

SENA also notes the importance of evaluating how CCAs can receive relevant information: "The Commission should consider whether statutory customer privacy requirements restrict whether and how customer-specific and/or aggregated load information can be provided to CCAs."[17] CalCCA supports the evaluation of this issue as soon as practical so CCAs are not unnecessarily precluded from having necessary information to plan for the loads they serve.

Another solution for waitlist transparency was provided by UC:

> However, if the Commission prefers to have the bulk of SB 237 load transfers determined before 2020 Annual Resource Adequacy obligations are evaluated, the process could be expedited by making the IOU's 2019 DA wait lists public on an anonymous basis (e.g. revealing lottery position and associated MWh only). This would allow Customers with lottery positions that are likely to be accepted under the expanded cap to explore their direct transaction options and the IOUs could begin notifying eligible customers immediately following the Commission's decision, anticipated on May 30, 2019.[18]

CalCCA recommends that each CCA receive information about which loads on the waitlist are in their service territory so that they can plan for departures.

D. DA-CCA Switching Should Be Addressed in This Proceeding

In its opening comments, CalCCA identified an issue that CalCCA proposed be addressed in Phase 1 of this proceeding. The issue relates to switching by DA customers, and restrictions currently imposed by the IOUs on the ability of a DA customer to switch service to its CCA. As described by CalCCA:

> The DA customers have been informed by the IOUs that if they switch to unbundled service provided by their CCA, they will no longer be able to later switch to an [Electric Service Provider ("ESP")] without returning to the waitlist. In contrast,

[16] AReM Opening Comments at 5.
[17] SENA Opening Comments at 7.
[18] UC Opening Comments at 4.

> DA customers are able to switch between ESPs without limitations on choice or timing. This creates an artificial barrier for unbundled customers and is contrary to the Commission's stated DA policies.[19]

After explaining the legal and policy rationale for eliminating these artificial restrictions, CalCCA urged that this issue be addressed as part of Phase 1 of this proceeding, and noted that additional clarification would be needed regarding how capacity should be addressed or set-aside when a DA customer switches to its CCA so that the DA cap is not inadvertently exceeded. CalCCA has reached out to various DA customer groups, and understands that some of the groups will be filing individual reply comments on the DA-CCA Switching Issue. Attachment A to these comments is a letter of support from one customer on this proposal.

E. The Idea of Ensuring Fairness for Certain Entities Is Not New as Highlighted by the Small Multijurisdictional Utilities

CalCCA neither supports nor opposes the proposals of the California Association of Small and Multi-Jurisdictional Utilities ("CASMU"), rather, CalCCA notes that the Commission has a history of ensuring fair treatment regarding the departure of DA on smaller entities. As stated by CASMU:

> The Commission has traditionally recognized the unique characteristics of the CASMU utilities and the significant differences between the CASMU utilities and the Large IOUs, routinely determining that 'the small size of [CASMU members] and the nature of their operations' make it inappropriate and burdensome for the Commission to impose certain requirements on CASMU members or require that the Commission allow CASMU members to take a more limited approach than that required for the Large IOUs.[FN] The Commission has noted that imposing certain planning requirements on CASMU members 'would only impose costs and inefficiencies on these small IOUs.'[FN]"[20]

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[19] CalCCA Opening Comments at 11. As further described hereunder, this issue is referred to as the "DA-CCA Switching Issue."
[20] CASMU Opening Comments at 6-7.

The current 4,000 GWh expansion of DA is occurring for the first time with CCAs now in operation. The procedures for the last expansion were decided in D.10-03-022, several months before the launch of the first CCA program.[21] Consistent with the Commission's exclusion of small and multi-jurisdictional utilities ("SMUs"), CalCCA asks that the Commission adopt measures to provide for fair treatment of CCAs at this time.[22]

II. TECHNICAL MATTERS

A. CalCCA Supports Clear Data on the Allocation of Load

CalCCA supports the request of AReM that "the Commission specify in its proposed and final decisions in the first phase of this proceeding[FN] the exact quantity by which the current DA participation cap will be increased for each service territory of the investor-owned utilities ("IOUs")."[23] In addition, as noted in CalCCA's opening comments, the Commission will need to indicate other loads that are unavailable, such as DA loads in excess of the cap at this time and CalCCA Supports Maintaining Appropriate PCIA Vintages

DACC requests clarification to ensure that PCIA Vintages remain in place for customers that move between DA and CCA.[24] CalCCA supports this approach.

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[21] MCE Clean Energy (then Marin Energy Authority) launched service in May 2010.
[22] While CASMU did not provide load figures for each SMU, it estimates that "23.96 GWh of the 4,000 GWh authorized by SB 237" would be allocated to them. (CASMU Opening Comments at 7.) If this represents 2% of their load, that would represent approximately 1,200 GWh of load served. Eight of the CCAs listed above are smaller than 1,200 GWh.
[23] AReM Opening Comments at 2.
[24] DACC Opening Comments at 8.

B. The Issue of PCIA Prepayment Should be Addressed in the PCIA Proceeding

PG&E raises a complexity regarding PCIA prepayment as a result of this decision. This matter should continue to be addressed in the PCIA Proceeding.[25]

III. CONCLUSION

CalCCA thanks Assigned Commissioner Picker and Assigned Administrative Law Judge Powell for the opportunity to provide these reply comments on the OIR.

Respectfully submitted,

/s/ Elizabeth Kelly

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

April 10, 2019

[25] "Additionally, the PCIA Decision 18-10-019 directed that parties develop, through working groups, a proposal to allow departed customers to pre-pay their obligations under the PCIA.[FN] This working group process is currently underway as part of Phase 2 of the PCIA proceeding, Working Group 2. Due to the complexities of DA expansion (e.g., newly expanded customer groups may comprise customers from multiple IOUs and CCAs, all with different "vintages" assigned under the PCIA), the pre-payment option considered in Decision 18-10-019 should be limited to DA and CCA customers at the time Decision 18-10-019 was issued. Requiring IOUs to negotiate with DA providers serving customers from this first phase of DA reopening and potential additional phases of DA expansion to negotiate would add significant complexity and cost." PG&E Opening Comments at 7.

ATTACHMENT A

Customer Letter of Support for DA-CCA Switching Issue

From: Hans Uslar <uslar@monterey.org>
Sent: Tuesday, April 9, 2019 8:23 AM
To: mp6@cpuc.ca.gov; LR1@cpuc.ca.gov; MGA@cpuc.ca.gov; CR6@cpuc.ca.gov; marcelo.poirier@cpuc.ca.gov; Christine.powell@cpuc.ca.gov; Ehern.seybert@cpuc.ca.gov; Kathleen.blake@cpuc.ca.gov
Cc: Bonnie Gawf <gawf@monterey.org>; Hans Uslar <uslar@monterey.org>; Ted Terrasas <terrasas@monterey.org>; J.R. Killigrew <jkilligrew@mbcommunitypower.org>; Tom Habashi <thabashi@mbcommunitypower.org>; Kimberly COLE <cole@monterey.org>
Subject: Scope of Rulemaking 19-03-009; Support for Clarifying Direct Access Switching Rules

Administrative Law Judge Powell, Commissioners and Energy Division staff,

I write you today to express support for CalCCA's request that the Commission clarify direct access switching rules to enable direct access customers, like the City of Monterey, to take unbundled energy service from their local community choice aggregator without having to return to the direct access wait list if they later choose to switch to a direct access provider. The City of Monterey supports having the widest possible options for procuring energy resources and believes the modest changes requested by CalCCA will remove barriers for us and other DA customers exploring service options with Monterey Bay Community Power.

I also ask that the issue be addressed by the Commission expeditiously within the Commission's first decision in the docket in order to facilitate the City of Monterey's ongoing energy procurement efforts to achieve our climate action goals.

Thank you.

Hans Uslar
City Manager
City of Monterey
(831) 646 - 3884

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

COMMENTS OF
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE PROPOSED DECISION

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May 20, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION

Pursuant to Rule 14.3 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure and the email of Administrative Law Judge ("ALJ") Powell, dated April 15, 2019, California Community Choice Association ("CalCCA") respectfully submits the following comments on the Proposed Decision issued on April 29, 2019 ("PD") and provides factual support as permitted by ALJ Powell's email. Pursuant to Rules 1.15 and 14.3, these comments are timely filed.

CalCCA supports the proposed two-year roll-out of the 4,000 gigawatt hour ("GWh") direct access ("DA") enrollment. This multi-year phase-in is consistent with past Commission precedent and the requests of various parties to this proceeding.

CalCCA recommends several modifications to the approach taken in the PD to address infirmities with the PD and to align it with existing Commission rules and process. In these comments, CalCCA requests that the Commission:

- implement the existing precedent of Resolution E-4907 for roll-outs of DA load departures;
- provide Community Choice Aggregators ("CCAs") with information on the DA waitlist necessary to engage in risk mitigation, load planning, and resource procurement;

- provide that CCAs concurrently receive a copy of any notice of intent to transfer ("NOI") and direct access service request ("DASR") approved by an Investor Owned Utility ("IOU") for any CCA customer;
- adopt CalCCA's Proposal of a cap on DA departures in CCA service territory consistent with other limits on DA departures;
- address CalCCA's switching rule modification in Phase 2 of the docket as stated in the Scoping Memo;
- clarify that a DA customer maintain its vintage when it takes service from a CCA; and
- launch of Phase 2 no later than third quarter of 2019.

I. JANUARY 2020 ENROLLMENT (PD SECTION 3.2)

A. SB 237 Does Not Require a Departure from the Commission's Practice with Respect to Resource Adequacy Requirements

The PD asserts that the exception from the requirement to provide year-ahead Resource Adequacy ("RA") forecasting is in order "[t]o comply with provisions of SB 237."[1] No provision of SB 237 requires an exception from this requirement. The law simply requires that "on or before June 1, 2019, the commission shall issue an order regarding direct transactions…."[2] This provision can be met by issuing a decision by June 1, 2019 which lays out a plan for implementation of SB 237. As is done elsewhere in the PD, the implementation plan of SB 237 should include ways in which SB 237 can be harmonized with other statutory provisions and Commission principles.[3]

[1] Proposed Decision at 11, emphasis added.
[2] Public Utilities Code Section 365.1(e).
[3] *See, e.g.,* PD at 18-19 (implementing the 4,000 GWh roll-out on a two-year timeframe).

B. SB 237 and Commission Precedent Support the Need for Additional Lead Time Prior to DA Load Departures to Ensure RA Compliance and Prevent Cost Shifting

The Commission has previously recognized the need for appropriate lead time for RA procurement, and in particular the year-ahead RA forecasting requirement. In Decision ("D.") 05-10-042, the Commission clearly stated:

> We recognize that a key issue for LSEs is their need to receive final, adjusted load forecasts from the CEC by July 1 to allow them sufficient time for final resource acquisition and a showing of such acquisition on September 30. This means that the LSEs' preliminary forecasts need to be submitted by the April 1 to May 1 period.[4]

In fact, the Alliance for Retail Energy Markets ("AReM") who has supported the expedited departure of DA in this proceeding previously opposed shortened timelines that would not allow for enough time to transact for RA resources. In D.11-06-022, AReM argued that "late notification of final RA requirements would further delay the IOU's process for selling excess Local RA to other LSEs, and otherwise limit the ability of LSEs to make the necessary RA purchases." [5]

This need for sufficient time to procure is particularly necessary in the current tight RA market. According to the Commission's RA Waivers and Penalties website, "[a] number of entities have requested year-ahead local, system, and flexible waivers for the 2019 compliance year."[6] In a tight RA market the risks to all load-serving entities ("LSEs") and ratepayers are higher – namely, the stranded costs of over-procurement and the penalty costs of under-procurement. By adopting the PD's timeline, the Commission could exacerbate RA market pressures by forcing more market players to compete in an already tight RA market in an unnecessarily compressed timeframe. This approach will likely result in increased costs for ratepayers, cost shifts to IOU and CCA customers

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[4] D.05-10-042 at 82-83, emphasis added.
[5] D.11-06-022 at 38-39.
[6] https://www.cpuc.ca.gov/General.aspx?id=6442460914.

due to unnecessary procurement for load that will be departing to DA, and increased numbers of RA waiver requests. These risks would be mitigated by maintaining and applying the existing rules for forecasting and departure equally to all LSEs.

C. To Avoid Cost Shifting and Discriminatory Treatment, the Commission Should Apply the Requirements Set Forth in Resolution E-4907 to DA Roll-Outs

The Commission already has in place procedures for load departures to avoid cost shifts and align departures with existing Commission RA requirements – Resolution E-4907. As a matter of sound policy and nondiscrimination, the Commission should apply consistent regulatory requirements for RA procurement for all departing loads. The Commission, through Resolution E-4907, implemented a process and timeline for CCAs specifically to ensure the CCAs "comply with Resource Adequacy requirements, as established in Section 380, before they serve customers."[7] The same compliance issues apply to DA load departures, and therefore the same rules should apply, regardless of whether the load departs for DA or CCA. The Commission's proposal for the roll-out of Phase 1, however, diverges from the timeline established in Resolution E-4907, and is inconsistent with prior Commission RA decisions. The Phase 1 proposal in particular waives the requirement for the April year-ahead forecasting of RA requirements. As discussed above in Section I.B., this is particularly problematic in the current tight RA market.

The PD should be revised to adopt a timeline consistent with Resolution E-4907 and prior Commission decisions to provide market stability, avoid stranded costs and avoid disparate treatment of LSEs that are similarly situated.

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[7] Resolution E-4907 at 1.

D. The PD's Basis for Not Applying Resolution E-4907 Is Flawed

The PD argues that a departure from the procedures in Resolution E-4907 for Energy Service Providers ("ESPs") is appropriate because ESP volumes are capped.[8] First, this is irrelevant because Resolution E-4907 applies to the departure of any CCA load of any size, no matter how much or how little departs in a year.

Second, this is based upon a false premise because, for any particular CCA, the volume of DA able to depart is effectively uncapped. The PD appears to presume that the amount of load departure from any one CCA will approximate the amount of load departure from the IOU service territory overall. This assumption, however, is contrary to the data available in this proceeding. The data set forth in Appendix 1 demonstrate that potential departures to DA are not proportionately borne by each LSE. An individual CCA could see load departures at higher magnitudes than the two percent anticipated by the Legislature and at a level that is difficult to plan for RA acquisition, and unnecessarily disruptive to the CCA, particularly in the shortened planning timeframe the PD adopts. This is discriminatory. While the PD asserts that it seeks to allow "equal access to the DA program," it places a heavy hand on the scale in favor of the large IOUs and the small IOUs to the detriment of CCAs. While the Commission has implemented a not-to-exceed cap for IOUs pursuant to the PD and entirely exempted small IOUs from DA departure, the Commission provides no such certainty or protections to the CCAs.

[8] "While the CCAs provide one year's notice for departing load, they are also permitted to operate without a cap on load that is permitted to depart bundled service; accordingly, they are not similarly situated to ESPs." PD at 11.

II. PCIA VINTAGE (PD SECTION 3.4.1)

A. CalCCA Requests That the Commission Further Clarify the PCIA Vintage Issue

The PD makes clear that if a CCA customer departs to DA, that customer maintains its vintage. The PD states: "[T]he vintage assigned to a customer who leaves an IOU's bundled service to join a CCA will not change when that customer leaves that same CCA's territory to join the DA program." [9]

However, the PD does not clarify the corollary of this concept where a DA customer moves to CCA. While currently implicitly stated, CalCCA requests that the Proposed Decision make explicit that a DA customer that takes service from a CCA maintains its vintage when it moves from service from an ESP to a CCA. As AReM stated in comments, "a customer on CCA service has already exercised its election to leave utility bundled service… Therefore, when the customer then elects to take service from an ESP, that election should not trigger a reassignment of their PCIA vintage."[10] Similarly, a DA customer has already exercised its option to leave bundled utility service, so an election to CCA should also not trigger a reassignment of their PCIA vintage.

III. WAITLIST DISCLOSURE (PD SECTION 3.4.3)

CalCCA thanks the Commission for acknowledging that "for procurement planning purposes, it is reasonable for CCAs to have advance notice of customer load that may depart CCA service as part of the DA expansion."[11] However, the Commission's proposed solution that CCAs receive only "aggregate load data" is insufficient.[12]

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[9] PD at 23.
[10] AReM Opening Comments on the Order Instituting Rulemaking ("OIR") at 6-7.
[11] Proposed Decision at 26.
[12] Proposed Decision at 26.

A. Aggregated Information Fails to Provide Many CCAs with Even the Load Expected to Depart

CalCCA has sought aggregated information from Pacific Gas & Electric Company ("PG&E") and Southern California Edison Company ("SCE"). The resulting data request responses demonstrate that aggregated information is not sufficient. As a result of the 15/15 rule,[13] many CCAs simply would not be informed of what loads are expected to depart from their territory. SCE, for example, aggregated all CCAs together, so no one CCA knows what their expected load departure would be.[14] Similarly, through PG&E's application of the 15/15 Rule, four of the twelve CCAs in PG&E's service area do not know what their expected load departure would be.[15] This situation particularly impacts the smallest of the CCAs for whom the departure of large commercial or industrial customers would have the most significant impact.

B. Providing Customer-Specific Data to CCAs Does Not Violate Confidentiality

CCAs already have access to customer-specific information and are subject to the confidentiality requirements of the Commission.[16] While the PD acknowledges the need for CCAs to have data for procurement planning purposes, it fails to provide CCAs with specific information –including waitlist rank, demand, location, customer type, load shape, and other customer characteristics – that a simple aggregated consumption amount (kWh) does not provide.

To accurately forecast their load and peak demand, procure resources to serve their customers, and optimize their portfolios, CCAs need data that reflect which customers are on the

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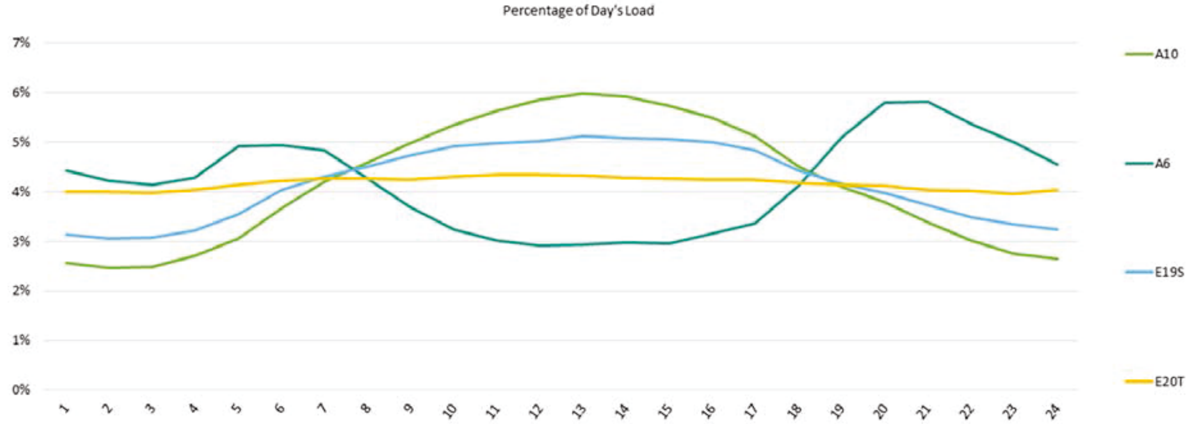
[13] "The "15/15 Rule" is a screen that requires that any aggregated customer-confidential information provided by the utilities be made up of at least fifteen customers, and that a single customer's load be less than fifteen percent of an assigned category. This tool was established in the Direct Access Proceeding via Decision (D.) 97-10-031." D.14-11-001 at 5, Footnote 8.
[14] See Attachment D.
[15] See Attachment C.
[16] *See, e.g.*, D.12-08-045 and the Community Choice Aggregator Non-Disclosure Agreement for each IOU.

DA waitlist to assess effects on load shape and the waitlist positions of those customers to assess likelihood of departure. This information enables CCAs and IOUs to plan and mitigate risk for the benefit of all customers and overall system reliability. Without granular information, the CCAs do not have enough data from which to plan or run scenarios.

While a simple MWh amount will allow a CCA to determine the potential impact to aggregate annual energy needs, this information is insufficient for resource and reliability planning. Commercial and industrial customers are not uniform in terms of demand on an hourly, daily, or seasonal basis. An aggregate departure of 50 GWh will have a different impact on the CCA's energy and Resource Adequacy requirements if it represents a large industrial customer with flat, round-the-clock consumption than if it represents a group of office buildings with lower load factors and mid-day peaks. Load profiles can differ dramatically across customer types as shown in Figure 1 below which sets forth the load shapes for commercial and industrial customers of Silicon Valley Clean Energy based upon customer data for a randomly selected weekday in July 2018. Additionally, some DA-eligible customers have more seasonal demand, whereas others have consistent needs throughout the year.

Figure 1.
Load Shapes of Commercial and Industrial Customers of Silicon Valley Clean Energy, July 2018



IOUs currently benefit from this information and can use it to determine how customer departures will impact their MW of peak load for Resource Adequacy filings, as well as their MWh of daily and monthly energy needs. Likewise, ESPs that are actively contracting with DA-eligible customers have knowledge of these customers' identities and their likely impact on capacity and energy requirements. CCAs are asking for the same information so that they can also contribute to maintaining system reliability.

CalCCA believes there are ways to provide customer-specific information to CCAs without violating any privacy or confidentiality provisions of the Commission. First, for the customers they serve, CCAs should receive the NOI to transfer to DA concurrently with the IOU. This information is the earliest indication of the amount of load that could potentially depart from CCA service and would allow for CCAs to plan for the potential range of departures it may face as soon as possible. Such forward-looking information on potential departures is a necessary piece of information for the CCA to have to engage in risk management over the coming years as load departs under the DA expansion.

Second, relevant information regarding the waitlist should be provided to the LSEs that serve them. Specifically, the proposal made by the University of California ("UC") in their Opening Comments should be adopted, namely, that the lottery position and associated MWh for those accounts on the DA wait list should be public.[17] The UC's proposal does not create confidentiality or 15/15 Rule issues. The proposal does not contain any customer-identifiable data; it contains only load and queue position. The only necessary modification to this proposal is that this information needs to be associated with the current LSE. As such, a CCA would receive a confidential table that provides the lottery position and the customer account number for each of

[17] UC Opening Comments on the OIR at 4.

its customers on the waitlist. CCAs do not need to have access to the other components of the waitlist that are not relevant for their resource planning.

C. CCAs Should Receive DASRs When They Are Received by IOUs

The PD also fails to provide CCAs with customer-specific information even after that current CCA customer has made a binding decision to depart from CCA service. Under the PD's proposal, a CCA would only receive aggregated information of departing load by July 15, 2019. Yet, the customer's DASR would be submitted to the IOU by July 31, 2019. Under this process, CCAs do not receive copies of DASRs for their customers, even though at this point the customer's departure is certain. Rather, CCAs will learn that a customer has left only through its billing operations – *i.e.*, electronic data interchange ("EDI") transfers with the IOU – which occur after the customer has already moved to an ESP. This illustrates another instance of disparate treatment among LSEs; CCAs are placed at a disadvantage relative to IOUs because CCAs would not be concurrently privy to the same information as the IOUs while being similarly situated to the IOUs with respect to load departures.

At the point a customer's ESP issues the DASR, the customer has decided and reached a "point of no return," and the affected CCA should be immediately informed of the proposed switching date. CalCCA requests that the Commission direct the IOUs to provide such DASRs to the relevant CCAs.

For example, PG&E Electric Rule 22.E.7 could be revised as follows:[18]

> PG&E will provide an acknowledgment of its receipt of the DASR to the ESP within two (2) working days of its receipt. PG&E will exercise best efforts to provide, within three (3) working days thereafter (and no later than five (5) working days), the ESP and the customer with a DASR status notification informing them as to whether the DASR has been accepted, rejected or deemed pending further information. As of July 1998, PG&E will provide this DASR status notification

[18] The corresponding sections for the other IOUs are SCE Electric Rule 22.E.7 and SDG&E Electric Rule 25.E.7.

> within three (3) working days. If accepted, the switch date determined in accordance with paragraphs 12 or 13 of this section, will be sent to the ESP, the former ESP **<u>or community choice aggregator (CCA)</u>**, if applicable, and the customer. If a DASR is rejected, PG&E will provide the reason for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed within eleven (11) working days following the status notification.

Until such changes are made to the Electric Rules, however, the IOUs should be directed to provide approved DASRs to the CCA serving that customer.

IV. <u>DISPARATE IMPACT ON CCAS AND THE CCA CAP (PD SECTION 3.4.6)</u>

A. Preventing Disparate Impacts on CCAs Is Consistent with and Supported by Commission Precedent

In its comments in this proceeding, CalCCA proposed "that the Commission protect against an allocation of the 4,000 GWh on any one CCA in excess of its fair share. This is to ensure that CCAs also do not face disparate impacts."[19] The PD asserts that "implementing such a cap would be unduly discriminatory as eligible DA customers would be denied the ability to choose to join the DA program solely on the basis that a CCA in [sic] entitled to a 'fair share' of that customer's load."[20]

First, CalCCA's position is to prevent disparate impacts on a CCA in a manner similar to the protection IOUs receive from unconstrained load departures due to the Legislature placing an overall cap of approximately 2% on departures from their service territories.

Second, such a cap is not "unduly discriminatory." In fact, it is the failure to adopt a CCA-specific cap that is unduly discriminatory. Notably, each large IOU has a specific cap. Small and multi-jurisdictional IOUs ("SMUs") are exempt from DA altogether. The approach proposed by CalCCA would allow customers to depart under a reasonable cap; whereas the Commission for

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[19] CalCCA Opening Comments on the OIR at 6.
[20] PD at 31.

SMUs has implemented a blanket prohibition on DA, fully eliminating choice for customers in those jurisdictions.

Third, the data provided in this proceeding support CalCCA's assertion that certain CCAs will bear a disproportionate burden of departures to DA on expedited timelines. In its opening comments, CalCCA provided information regarding the impacts on different CCAs. This concern is substantiated by the data as described in Section VI and is reflected in Appendix 1.

Most importantly, because the second expansion of DA proposed in the PD will occur under a refreshed waitlist within the lottery system, it is entirely unclear how much load will be subject to departure within any specific CCA. Without a reasonable cap in place, no CCA will be able to plan for anticipated load departures.

B. Recommending that CCAs Impose Exit Fees Is Not the Answer; Good Planning and Fair Rules Are

The PD states that "CCAs should consider revising their risk management plans or implementing mechanisms that are similar to the regulatory framework established for PCIA."[21] This proposal raises a number of legal, policy, and procedural issues significantly beyond the scope of this proceeding, but more fundamentally, this is not customer-friendly. Adding yet another charge to customer bills will add to customer confusion and inability to easily compare LSEs on an apples-to-apples basis. Additionally, to implement this approach, the Commission would need to direct all IOUs to modify their tariffs and make any technology or billing infrastructure upgrades to ensure that the approach could be seamlessly implemented. This is likely impossible to implement within the next several months before DA is re-opened and will result in unnecessary expense to all utility customers.

[21] PD at 31-32.

A far better approach is to modify the PD to provide CCAs with the data they need to appropriately plan. CalCCA believes it is prudent for CCAs to plan for load departures, and mitigate the negative impacts of departures, rather than proposing to laden customers with more fees, which needlessly increases the risk of customer confusion and litigation over the terms of another exit fee.

V. PHASE 2 – RECOMMENDATION TO LEGISLATURE ON INCREASING DIRECT ACCESS (PD SECTION 3.4.5)

A. CalCCA Recommends that the Commission Ensure Sufficient Process in Phase 2 to Ensure There Is the Evidentiary Support Necessary for the Findings Required by Section 365.1("f")(2)

CalCCA supports the launch of Phase 2 of the proceeding no later than the end of the third quarter of 2019. CalCCA supports a robust stakeholder process to develop the recommendation to the Legislature. It will be essential to have evidence on the record in order to make the findings required by Section 365.1("f")(2):

> In developing the recommendations pursuant to subdivision (f), the commission shall find all of the following:
> (A) The recommendations are consistent with the state's greenhouse gas emission reduction goals.
> (B) The recommendations do not increase criteria air pollutants and toxic air contaminants.
> (C) The recommendations ensure electric system reliability.
> (D) The recommendations do not cause undue shifting of costs to bundled service customers of an electrical corporation or to direct transaction customers.

Each of the four areas described in Section 365.1("f")(2) requires findings that are supported by facts and evidence. It is likely that evidentiary hearings will be required for this phase and the Commission should plan accordingly. The findings and recommendations need to be subject to a robust discussion and record to ensure the state can continue to meet reliability and GHG reduction goals while ensuring fair treatment of residential and other customers that do not depart for DA service.

B. The DA-CCA Switching Issue Should Be Addressed in Phase 2 Pursuant to the Scoping Memo

CalCCA opposes the improper disposition of the issue of switching between DA and CCA service as currently set forth in the PD.[22] The Scoping Memo issued on April 17, 2019 ("Scoping Memo") provided that "the Commission will consider CalCCA's fourth and fifth [pertaining to DA-CCA switching] issues when it finalizes the scoping memo for Phase 2."[23] Rather than considering this issue in Phase 2, based on additional input, facts and support, the PD prematurely denies the proposal. The PD's disposition of the DA-CCA issue should be modified so the matter can be properly addressed in Phase 2.

Rule 7.3 of the Rules of Practice and Procedure provides that a scoping memo "shall determine the… issues to be addressed." Here, the Scoping Memo provides that the matter of DA-CCA switching would be addressed in Phase 2, not in the PD. The California Court of Appeals has found – even in a quasi-legislative proceeding – that where the Commission has addressed matters "beyond the scope of issues identified in the scoping memo" the Commission has "failed to proceed in the manner required by law [(§ 1757.1(a)] and that the failure was prejudicial."[24]

VI. <u>RESPONSE TO REPLY COMMENTS OF THE DIRECT ACCESS CUSTOMER COALITION</u>

On April 12, 2019, CalCCA requested the opportunity to file a Response to the Reply Comments by the Direct Access Customer Coalition ("DACC") to address erroneous statements of DACC.[25] DACC called into question the veracity and the reliability of the information set forth

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[22] PD at 27.
[23] Scoping Memo at 3.
[24] *S. California Edison Co. v. Pub. Utilities Com.*, 140 Cal. App. 4th 1085, 1106 (2006).
[25] DACC Reply Comments at 3.

by CalCCA without providing support for DACC's own assumptions in their Reply Comments. As DACC stated:

> Furthermore, the factual assertions that CalCCA has made regarding the potential load losses that individual CCAs might experience are anecdotal at best and likely represent hypothetical worst-case scenarios for a small number of CCAs. In any event, the Commission cannot reasonably view these unverified and unvetted claims as informative, much less reliable, for its deliberative purposes.[26]

On April 15, 2019, ALJ Powell via email stated that "CalCCA may address this issue in its comments to the PD." Attached to these Comments are the data substantiating CalCCA's assertions regarding the disparate impact CCAs would bear under the PD.

DACC's reply comments regarding the veracity of CCA data is baseless. As demonstrated in Appendix 1, several CCAs bear greater than a proportionate share of DA departures, and some bear triple the proportion of departures the IOU would face.[27] The departure amounts for each CCA in SCE's service territory is entirely unknown since, pursuant to the 15/15 Rule, SCE aggregated information across all of the SCE-area CCAs.[28]

VII. **<u>CONCLUSION</u>**

CalCCA thanks Assigned Commissioner Picker and Assigned Administrative Law Judge Powell for the opportunity to provide these comments on the Proposed Decision.

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[26] DACC Reply Comments at 3.
[27] For purposes of this filing, we use data pertinent to CCAs located in Pacific Gas & Electric's ("PG&E's") footprint since that is the CCA-specific data available to CalCCA at this time. CalCCA notes that information for King City Community Power cannot be provided publicly at this time due to the Commission's rules on confidentiality.
[28] See Attachment D.

Respectfully submitted,

/s/ Elizabeth Kelly

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

May 20, 2019

Appendix 1
Expected Departures of DA Load from CCAs in PG&E Territory

Community Choice Aggregator	2019 Energy (GWh) [A]	2019 Waitlist (GWh) [B]	2019 Waitlist Expected to Clear (GWh) (Proposed Decision) [C]	% of Load on 2019 Waitlist [D]	% of Load Expected to Clear from 2019 Waitlist (Proposed Decision) [E]
Clean Power San Francisco	2,666	142	31	5.33%	1.16%
East Bay Community Energy	5,699	393	188	6.90%	3.30%
King City Community Power	37	*	*	*	*
Marin Clean Energy	5,275	158	60	3.00%	1.14%
Monterey Bay Community Power	3,218	105	41	3.26%	1.27%
Peninsula Clean Energy	3,609	134	16	3.71%	0.44%
Pioneer Community Energy	1,138	32	*	2.81%	*
Redwood Coast Energy Authority	699	7	*	1.00%	*
San Jose Community Energy	3,338	142	43	4.25%	1.29%
Silicon Valley Clean Energy	3,974	482	21	12.13%	0.53%
Sonoma Clean Power	2,532	86	25	3.40%	0.99%
Valley Clean Energy	744	32	*	4.30%	*

Column A: The expected 2019 load of each CCA in PG&E's service area in GWh. This is derived from PG&E's Energy Resource Recovery Account ("ERRA") Testimony prepared for the ERRA "November Update." The relevant excerpt from PG&E's Testimony is set forth as Attachment A.

Column B: The load (in GWh) on the waitlist by CCA currently serving that load. This is set forth in the response of PG&E to CalCCA's Data Request CalCCA_001-Q04 which is set forth as Attachment B.

Column C: The amount of load expected to clear off the waitlist in each CCA's territory based on the load PG&E expects to clear off the 2019 Waitlist under the Proposed Decision. This is set forth in the response of PG&E to CalCCA's Data Request CalCCA_003-Q01 which is set forth as Attachment C.

Column D: The percent of each CCA's load on the 2019 Waitlist. [Column D] = [Column B] / [Column A]

Column E: The percent of each CCA's load on the 2019 Waitlist expected to clear based on the Proposed Decision. [Column E] = [Column C] / [Column A]

Attachment A
PG&E ERRA Testimony Excerpt

Application: 18-06-001
(U 39 E)
Exhibit No.: PG&E-6
Date: November 7, 2018
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

UPDATE TO PREPARED TESTIMONY

2019 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION

PUBLIC VERSION

TABLE 2-3
2019 ENERGY (GIGAWATT HOUR)
PEAK DEMAND MW REQUIREMENTS

2019 ENERGY REQUIREMENTS (GWH)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	**Energy Load (GWh)**													
2	Retail Sales	[redacted]												86,600
3	Conservation and Energy Efficiency	(346)	(346)	(346)	(346)	(346)	(346)	(346)	(346)	(346)	(346)	(346)	(346)	(4,155)
4	Distributed Generation													
5	Solar	(72)	(85)	(140)	(160)	(187)	(192)	(195)	(182)	(157)	(136)	(96)	(81)	(1,682)
6	CHP	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(54)
7	Fuel Cell & Other	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(217)
8	Electric Vehicles	36	36	36	36	36	36	36	36	36	36	36	36	436
9	Electrification	2	2	2	2	2	2	2	2	2	2	2	2	23
10	Direct Access													
11	Direct Access	(747)	(758)	(758)	(784)	(803)	(830)	(861)	(873)	(863)	(805)	(792)	(759)	(9,631)
12	Community Choice Aggregation													
13	Marin Clean Energy	(475)	(411)	(402)	(403)	(410)	(454)	(495)	(494)	(474)	(403)	(414)	(441)	(5,275)
14	Sonoma Clean Power	(221)	(194)	(206)	(191)	(195)	(212)	(222)	(218)	(214)	(211)	(208)	(240)	(2,532)
15	Clean Power San Francisco	(175)	(177)	(166)	(212)	(238)	(236)	(233)	(249)	(243)	(237)	(248)	(252)	(2,666)
16	Peninsula Clean Energy	(320)	(303)	(285)	(288)	(283)	(288)	(296)	(313)	(309)	(295)	(310)	(318)	(3,609)
17	Silicon Valley Clean Energy	(334)	(318)	(304)	(309)	(314)	(335)	(346)	(342)	(363)	(335)	(335)	(339)	(3,974)
18	Redwood Coast Energy Authority	(61)	(54)	(60)	(58)	(58)	(57)	(58)	(57)	(56)	(60)	(58)	(62)	(699)
19	Pioneer Community Energy	(95)	(82)	(76)	(76)	(86)	(104)	(122)	(122)	(110)	(81)	(86)	(96)	(1,138)
20	Monterey Bay Community Power	(257)	(225)	(248)	(254)	(282)	(285)	(301)	(297)	(275)	(274)	(256)	(264)	(3,218)
21	Valley Clean Energy	(53)	(46)	(47)	(49)	(61)	(75)	(88)	(84)	(70)	(59)	(54)	(58)	(744)
22	East Bay Community Energy	(504)	(486)	(446)	(457)	(442)	(464)	(489)	(502)	(482)	(458)	(467)	(501)	(5,699)
23	King City Community Power	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(3)	(3)	(3)	(37)
24	San Jose Community Energy	(13)	(13)	(165)	(322)	(324)	(362)	(386)	(395)	(373)	(320)	(325)	(341)	(3,338)
25	UFE, Transmission & Distribution Losses	[redacted]												3,493
26	Total Requirement	[redacted]												41,884

Attachment B
PG&E Data Request Response CalCCA_001-Q04

PACIFIC GAS AND ELECTRIC COMPANY
Direct Access OIR SB 237
Rulemaking 19-03-009
Data Response

PG&E Data Request No.:	CalCCA_001-Q04		
PG&E File Name:	DirectAccessOIR-SB-237_DR_CalCCA_001-Q04		
Request Date:	March 21, 2019	Requester DR No.:	001
Date Sent:	April 2, 2019	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Elizabeth Kelly

QUESTION 04 – DA WAITLIST

With regards to your DA waitlist that went into effect on January 1, 2019, please provide the following, in each case providing an explanation of the figures or any methodologies used to derive the figures.

A. The total amount of GWh on the waitlist.

B. The total amount of GWh on the waitlist by LSE currently serving that load (i.e. by CCA and by you.)

C. The total number of service accounts on the waitlist by LSE currently serving that load.

ANSWER 04

A. The total amount of load on the waitlist that went into effect on January 1, 2019 is 3,637 GWh based upon billed usage in 2018.

B. The total amount of GWh (rounded to the nearest GWh) on the waitlist by LSE currently serving the load is shown in the table below;

LOAD SERVING ENTITY	LOAD (GWh)
Clean Power San Francisco	142
East Bay Clean Energy	393
Monterey Bay Community Power	105
MCE Clean Energy	158
Peninsula Clean Energy	134
Pioneer Community Energy	32
Redwood Coast Energy	7
Sonoma Clean Power	86
San Jose Clean Energy	142
Silicon Valley Clean Energy	482
Valley Clean Energy Authority	32
PG&E	1924

C. The total number of service accounts on the waitlist by LSE currently serving that load is shown in the table below:

LOAD SERVING ENTITY	No Of SA IDs
Clean Power San Francisco	493
East Bay Clean Energy	1015
Monterey Bay Community Power	818
MCE Clean Energy	779
Peninsula Clean Energy	525
Pioneer Community Energy	187
Redwood Coast Energy	60
Sonoma Clean Power	463
San Jose Clean Energy	307
Silicon Valley Clean Energy	609
Valley Clean Energy Authority	135
PG&E	7069

*** Note The total GWh and SA ID counts for King City Community Power were omitted per the 15/15 rule adopted by the CPUC. PG&E believes this is more appropriate than aggregating the load with another CCA provider.

Attachment C
PG&E Data Request Response CalCCA_003-Q01

PACIFIC GAS AND ELECTRIC COMPANY
Direct Access OIR SB 237
Rulemaking 19-03-009
Data Response

PG&E Data Request No.:	CalCCA_003-Q01		
PG&E File Name:	DirectAccessOIR-SB-237_DR_CalCCA_003-Q01		
Request Date:	May 1, 2019	Requester DR No.:	003
Date Sent:	May 8, 2019	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Elizabeth Kelly

QUESTION 01 – UPDATED WAITLIST CLEARING FIGURES

Please provide the aggregated GWh (rounded to the nearest GWh) by LSE of the load PG&E expects to clear off the 2019 Waitlist under the Phase 1 Increase as set forth in the Proposed Decision issued on April 29, 2019.

ANSWER 01

PG&E estimates that it will have a new direct access allowance of 937 GWh based upon proposed Overall DA Load Cap of 10,457 GWh for 2019 and its total direct access load of 9,695 GWh as of March 2019.

PG&E is providing the aggregated GWh (rounded to the nearest GWh) by Load Serving Entity (LSE) of the load PG&E expects to clear off the waitlist. In the table below, PG&E used a total allocation of 925 GWh as the total load of the next customer on the 2019 Wait List would cause PG&E to exceed the Overall DA Load Cap of 10,457 GWh.

LOAD SERVING ENTITY	LOAD (GWh)
Clean Power San Francisco	31
East Bay Clean Energy	188
King City Community Power ***	0
Monterey Bay Community Power	41
MCE Clean Energy	60
Peninsula Clean Energy	16
Pioneer Community Energy ***	0
Redwood Coast Energy ***	0
Sonoma Clean Power	25
San Jose Clean Energy	43
Silicon Valley Clean Energy	21
Valley Clean Energy Authority ***	0
PG&E	492
Total:	925

*** Note: The total GWh for King City Community Power, Pioneer Community Energy, Redwood Coast Energy and Valley Clean Energy Authority shows as zero (0) per the 15/15 rule adopted by the CPUC. PG&E believes this is more appropriate than aggregating the load with another CCA provider.

Attachment D
SCE Data Request Response CalCCA-SCE-004 Q1

Southern California Edison
R.19-03-009 – SB 237 OIR

DATA REQUEST SET C a l C C A - S C E - 0 0 4

To: CalCCA
Prepared by: Estella Banuelos
Job Title: Senior Analyst
Received Date: 5/1/2019

Response Date: 5/8/2019

Question 01:
Please provide the aggregated GWh (rounded to the nearest GWh) by LSE of the load SCE expects to clear off the 2019 Waitlist under the Phase 1 Increase as set forth in the Proposed Decision issued on April 29, 2019.

Response to Question 01:
The table below provides the aggregated load, organized by LSE of the load, that SCE expects to clear off the 2019 Waitlist under the Phase 1 Increase as set forth in the Proposed Decision issued on April 29, 2019.

LSE	Annualized Load Offering GWh
SCE / DA	1,465
CPA / RMEA / AVCE / LCE / PRIME / SJP**	277
Total	1,742

**These LSEs were combined in the table above due to customer confidentiality concerns, pursuant to the "15/15 Rule" adopted by the Commission in D.97-10-031.

Customer Confidentiality: The IOUs are authorized to provide aggregated usage data to the extent customer confidentiality is not compromised. The "15/15 Rule" was adopted by the CPUC in the Direct Access Proceeding (CPUC Decision 97-10-031) to protect customer confidentiality. The 15/15 Rule requires that any aggregated information provided by the IOUs without customer written authorization must be made up of at least 15 customers and a single customer's load must be less than 15 percent of an aggregated category. If the number of customers in any one group falls below 15, or if a single customer's load accounts for more than 15 percent of the total group data, data must be further aggregated before the information is released. If the 15/15 Rule is triggered for a second time after the data has been screened once already using the 15/15 Rule, the Rule further requires that the customer be dropped from the aggregated data. The 15/15 Rule ensures that the identity of larger customers are protected from disclosure.

FILED
05/28/19
04:59 PM

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

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

**REPLY COMMENTS OF
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE PROPOSED DECISION**

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Counsel for:
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May 28, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	Rulemaking 19-03-009 (Filed March 14, 2019)

REPLY COMMENTS OF
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE PROPOSED DECISION

Pursuant to Rule 14.3 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, California Community Choice Association ("CalCCA") respectfully submits the following reply to the comments on the Proposed Decision issued on April 29, 2019 ("PD"). Pursuant to Rules 1.15 and 14.3, these comments are timely filed.

I. ENROLLMENT TIMELINES

A. Consistent Application of Resolution E-4907 Is Essential to Ensure Appropriate RA Procurement and to Prevent Cost-Shifting

In their comments on the PD, various parties support an expedited timeline for the reopening of direct access ("DA") that conflicts with Resolution E-4907. CalCCA strongly opposes this approach because it contravenes existing requirements for CCAs and creates an untenable environment for all LSEs to forecast and procure resource adequacy ("RA") in an already constrained market. This will drive up RA costs for California ratepayers, while suppressing accurate reliability planning and execution. CalCCA continues to strongly support the use of existing precedent, Resolution E-4907, to allow for appropriate time horizons to plan for departures and meet all compliance requirements.[1] From the perspective of trying to maximize the effectiveness of the year-ahead RA planning process, which is the reason Resolution E-4907 was passed, there is no basis for treating this DA reopening any differently from any load departure to

[1] While Commercial Energy asserts that each LSE will be able file their August 16, 2019 updated RA forecast and "make adjustments to procurement before the customers begin service on Jan. 1, 2020" (Comments of Commercial Energy on PD at 5), this oversimplifies the requirements imposed on LSEs. In the year-ahead RA filings in October of each year, LSEs must demonstrate that they have procured 90% of system RA in summer months and 90% of flexible RA and 100% of local RA in each month. See, 2019 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings, October 3, 2018 at 5. Available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442459140

CCA. CalCCA proposed appropriate modifications to the Resolution E-4907 for DA departures and this is provided again in Attachment A.

Resolution E-4907 addresses the same departure and stranded cost issues that parties are grappling with in this proceeding, would provide a clear and consistent 1-year timeline to ensure all LSEs comply with the year-ahead RA process before serving customers (a requirement the Commission explicitly imposed on CCAs in Resolution E-4907), would minimize cost-shifts, and would even provide an established waiver process if LSEs want to expedite the process.

B. The Extensive Waivers to Existing Rules Resulting from the Expedited Enrollment Timeline Are Troubling

In their comments on the PD, Pacific Gas and Electric Company, Southern California Edison and San Diego Gas and Electric (the "Joint IOUs") propose several modifications of existing processes in order to implement the PD as drafted.[2] These extensive deviations, waivers and cancellations are unnecessary and inadvisable. The utilities have not presented any rationales that would support these substantial deviations from current practices other than an underlying view that the compressed timelines presented in the PD do not allow for adherence to current rules. Rather than scrapping or deviating from existing rules and precedent, the Commission should adopt a timeline for customer departures that conforms to existing requirements, including the timeline the Commission has implemented in Resolution E-4907.

To implement these deviations, waivers and cancellations, the Joint IOUs propose "to implement all necessary tariff revisions by June 14, 2019, via a Tier 1 advice letter."[3] CalCCA opposes this approach as it does not provide for sufficient review by impacted parties to ensure compliance with the Commission's ultimate decision and because Tier 1 advice letters are intended for routine, non-controversial issues which an expanded DA application for all LSEs is not.

II. PCIA VINTAGE

CalCCA's Opening Comments asked the Commission to clarify that a DA customer maintains its vintage when it takes service from a CCA. The California Large Energy Consumers

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[2] These modifications include: a deviation from the terms and conditions stated in each utility's Six-Month Notice, waiver of "the safe harbor, Transitional Bundled Service ("TBS") and bundled portfolio service provisions in the Six-Month Notice," and cancellation of the Notice in certain circumstances. Comments of Joint IOUs on PD at 1-2.

[3] Comments of Joint IOUs on PD at 5.

Association ("CLECA") made the same recommendation for an administrative clarification to ensure consistency.[4] CalCCA supports this clear and simple approach and opposes the Joint IOUs' new vintaging proposal that modifies – does not clarify – existing rules.[5]

III. CUSTOMER CONFIDENTIALITY AND THE WAITLIST

A. The Confidentiality and 15/15 Rules Are Misapplied in Parties' Comments

CLECA proposes that the PD "explicitly reference critical rules on protection of confidential customer information set in D. 14-05-016; the PD should explain that those rules serve to protect particularly commercially sensitive industrial customer data, and ensure they apply to the release of aggregated load data to [CCAs]."[6] CLECA commits legal error in its proposed application of: (1) D.14-05-016, which is not applicable to CCAs,[7] (2) Section 394.4(a) of the California Public Utilities Code regarding confidentiality, which does not apply to waitlist number or data that CCAs are already properly in possession of,[8] and (3) the 15/15 Rule, which does not apply to waitlist numbers. CCAs already have in place applicable non-disclosure agreements with the IOUs with regards to confidentiality of customer data and the Commission has applied the same rules and responsibilities regarding data access to CCAs as it has IOUs.[9]

B. Aggregated Information Is Not Sufficient for Planning Purposes

CCAs' request to have complete information regarding their customers on the waitlist is not academic. CCAs request this data to appropriately plan for customer departures. The assertion that "aggregated data <u>should</u> give CCAs and ESPs all the information they need for planning purposes"[10] is an erroneous assumption. The need for data regarding the waitlist is set forth in

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[4] "The PCIA vintage is determined when a ~~CCA~~ customer leaves bundled service <u>for either CCA or ESP service</u>." Comments of CLECA on the PD at 1.
[5] The Joint IOUs, however, recommend an entirely new approach to vintaging for DA customers in the guise of creating "parity with regard to PCIA vintaging." Joint IOUs at 5.
[6] CLECA at 1.
[7] The Decision is applicable only to "local government entities, researchers, and state and federal agencies" seeking customer load data for research purposes. D. 14-05-016 at 1.
[8] Comments of CLECA on PD at 2
[9] "In our view, a policy of granting CCAs full access to customer usage data and holding CCAs responsible for protecting the advanced metering data that they obtain from PG&E, SCE and SDG&E <u>provides the CCAs the same usage rights and responsibilities as a utility</u>. Moreover, in this particular situation, such a policy provides CCAs with all rights to data that it requests." D.12-08-045 at 25, emphasis added.
[10] Comments of Advanced Energy Economy ("AEE") and the Advanced Energy Buyers Group ("AEBG") on PD at 9.

CalCCA's comments on the OIR and the PD. Moreover, speculative comments regarding usage of data beyond planning for load departures and to avoid cost shifts by CCAs are not supported by the record in this docket and should be rejected as a legitimate rationale for denying CCAs the data they need to plan. The IOUs already receive this information and there is no principled reason why a CCA, which is in the same position as the IOU in reliably serving its community, should not have equivalent information on the same terms as the IOUs, as set forth on Attachment A.

IV. CCA CAP

A. The CCA Cap Is Not Discriminatory and Is Consistent with Customer Choice

CalCCA throughout this proceeding has sought to avoid disproportionate allocations of DA departure from individual CCAs, consistent with other limits on DA departures. Certain parties' opening comments view this protection as "discriminatory" and "stifl[ing] customer choice."[11] These concerns are inaccurate and misplaced.

The term discrimination has been widely used – and widely misused – in this proceeding. Parties have viewed the CCA cap as discriminatory. Parties have viewed the use of different waitlists as discriminatory.[12] However, for a decision to be discriminatory, it must make an unfair or prejudicial distinction between different categories of people or things. It is not unfair or prejudicial to develop rules to provide safeguards for CCAs in a manner that is consistent with the overall approach to capping load departures contained in legislative analysis. The proposed CCA cap is fully consistent with and advances customer choice, contrary to the assertion of Commercial Energy, which asserts that the CCA cap is "inconsistent with customer choice and should be rejected."[13] In CCA service areas, all customers have a choice of energy provider. Outside of CCA service areas, commercial customers have the option for DA only in large IOU territories subject to a cap. To the extent load departures to DA are concentrated in CCA territories, that concentration deprives customers in other IOU, non-CCA areas, the option of an alternative service provider.

B. Alternate LSE Cap Proposal of EBCE

CalCCA continues to support its proposal to cap loads in CCA territories. However, if the

[11] *See*, Comments of AEE and AEBG on the PD at 9.
[12] See, Comments of Energy Producers and Users Coalition ("EPUC") on PD at 1; See, also, Comments of Shell Energy North America ("SENA") on PD at 3-4.
[13] Comments of Commercial Energy on PD at 7.

Commission is not inclined to adopt the CalCCA proposal, East Bay Community Energy ("EBCE") proposes an alternative to the CCA cap in its Opening Comments. "For SB 237 volumes, the Commission should adopt a cap of 3% of total load for each non-DA LSE (*i.e.*, CCAs and IOUs), spread over two years. This would put all CCAs and IOUs on an equal footing with respect to DA reopening impacts. Furthermore, a 3% cap would accommodate most would-be DA customers on the 2019 waitlist."[14] CalCCA does not oppose this proposal.

C. Proliferating Exit Fees Are Not a Solution and Harm Customer Choice

CalCCA thanks the Commission for acknowledging in the PD the right of CCAs to implement exit fees. However, as noted in CalCCA's comments on the PD, exit fees could add to customer confusion and are not customer-friendly. Furthermore, it is impractical for CCAs to implement an exit fee structure in the proposed departure timeline. The Direct Access Customer Coalition ("DACC") appears to share CalCCA's concerns regarding the deleterious impacts of proliferating exit fees noting that "further exit fees will impair retail competition, inhibit customer choice and actually be deleterious to CCA interests as it could encourage DA-eligible customers currently taking CCA service to depart to bundled service so as not to be subject to CCA exit fees that might be applied in the future that would make a move to direct access less economical." CalCCA agrees that further exit fees are not the preferred answer. Instead, the Commission should develop a cap on load departures within CCA service territories to mitigate the need for exit fees.

V. PHASE 2 AND THE DA-CCA SWITCHING ISSUE

Commercial Energy and DACC support the Commission's early determination regarding DA-CCA switching rules as set forth in Section 3.4.5 of the PD.[15] CalCCA opposes prejudging this issue and asks that the Commission address the proposed switching rule modification in Phase 2 of the docket as stated in the Scoping Memo. CalCCA asks that this issue be fully heard.

VI. CONCLUSION

CalCCA thanks Assigned Commissioner Picker and Assigned Administrative Law Judge Powell for the opportunity to provide this reply to the comments on the Proposed Decision.

[14] Comments of EBCE on PD at 7.

[15] Comments of Commercial Energy on PD at 6; Comments of DACC on PD at 9-10.

Respectfully submitted,

/s/ Elizabeth Kelly

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

May 28, 2019

ATTACHMENT A

ORDERING PARAGRAPH AND DA EXPANSION TIMELINE

New Ordering Paragraph, replacing Ordering Paragraphs 3-5:

The Direct Access (DA) enrollment schedule to enroll new loads is as set forth as follows:

DA Expansion Timeline Consistent with Resolution E-4907

Date	DA Customer and ESP Action
Day 1, Year 1 (On or before January 1 Year 1)	(1) The prospective DA customer submits its Intent to Take DA Service to Energy Division and to the LSE serving that load.
Day 1 – 90, Year 1	(1) The CPUC sends a letter confirming that it has received the Intent to Take DA Service. This letter informs the ESP about any cost recovery mechanism. If and when the CPUC requests additional information from an ESP, the ESP shall respond to CPUC staff within 10 days, or notify the staff of a date when the information will be available. (2) The CPUC provides the ESP with its findings regarding any cost recovery that must be paid by customers of the CCA in order to prevent cost shifting. (3) The ESP and the Utility should Meet-and-Confer regarding the ESP's ability to conform its operations to the Utility's tariff requirements.
Day 1 – 90, Year 1	(1) The ESP submits its registration packet to the CPUC, including: a. Signed UDC-ESP service agreement with the utility, b. Completed ESP Registration Application Form, c. Fingerprints are prescribed for required personnel d. Applicable bond amount e. Scheduling coordinator agreement f. ESPs offering electric service to residential or small commercial customers, submit a copy of your Section 394.5 Notice to the Energy Division of the CPUC on or before the date you sign up your first customer or when the first standard service plan filing is due, whichever is earliest
Day 90 – 120, Year 1	(1) If the registration packet is complete, the CPUC confirms Registration as an ESP.
April, Year 1	(1) The ESP submits its year ahead Resource Adequacy forecast (P.U. Code Section 380)
August, Year 1	(1) The ESP submits its updated year-ahead RA forecast

Date	DA Customer and ESP Action
October Year 1 (75 days before service commences)	(1) ESPs submit their Monthly load migration forecast for the Resource Adequacy program, filed about 75 days prior to the compliance month.
Within 30 days of the CCA's or ESP's Commencement of Customer Automatic Enrollment	(1) Once notified of the DA departure, the Utility shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process.
January 1, Year 2	(1) ESP begins service.

ORDERING PARAGRAPH AND WAITLIST

New Ordering Paragraphs, replacing Ordering Paragraph 6:

Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall revise Direct Access Program rules such that each affected Community Choice Aggregator (CCA) receives a confidential table that provides the lottery position and the customer account number for each of its customers on the waitlist.

Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall revise their electric rules such that any affected Community Choice Aggregator (CCA) shall be informed of the proposed switching date.

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

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

COMMENTS OF MARIN CLEAN ENERGY AND CITY OF LANCASTER IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING INVITING COMMENTS ON DRAFT POTENTIAL AND GOALS STUDY

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May 21, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

COMMENTS OF MARIN CLEAN ENERGY AND CITY OF LANCASTER IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING INVITING COMMENTS ON DRAFT POTENTIAL AND GOALS STUDY

Marin Clean Energy ("MCE") and the City of Lancaster ("Lancaster") submit the following comments in response to the *Administrative Law Judge's Ruling Inviting Comments on Draft Potential and Goals Study* ("Ruling"), filed on May 1, 2019. As the two Community Choice Aggregators ("CCAs") who are currently administering energy efficiency ("EE") programs, MCE and Lancaster appreciate the opportunity to provide input on the "2019 Energy Efficiency Potential and Goals Study" ("Navigant Study"). MCE and Lancaster provide the following comments in an effort to engage with Navigant and the Commission to ensure that non-investor-owned utility ("IOU") EE program administrators ("PAs"), such as CCAs and Regional Energy Networks ("RENs"), are appropriately considered and distinguished from their IOU counterparts. MCE and Lancaster hope that the below comments serve to shed light on some areas where the Commission should carefully consider the Navigant Study and its relationship to non-IOU EE portfolios.

I. COMMENTS

A. The Navigant Study Should Provide Value to Both IOUs and CCAs

MCE and Lancaster believe that the Navigant Study should aim to provide as much value for CCA EE programs as it does for IOU EE programs, since the Navigant Study is funded by *all* ratepayers. Unfortunately, the Navigant study does not currently provide the same level of value to CCAs as it does to the IOUs. This is because the energy savings and potential are only identified on an IOU service territory level, and not on a CCA or REN level. This data-driven information helps the IOUs design EE portfolios in addition to assign them goals. MCE and Lancaster desire to have more detailed information on EE potential in their respective service territories to help inform future program design and development.

B. There Are Many Uncertainties Surrounding Navigant's Proposed Top-Down Disaggregation Approach for Determining Energy Savings Goals and Potential for CCAs and RENs

Lancaster and MCE are concerned about Navigant's high-level approach to parsing out savings for CCAs and RENs as proposed during a workshop in January 2019.[1] Navigant is suggesting to "conduct a top-down disaggregation of IOU level results" for CCAs and RENs as a "post-processing step based on population and historic program savings data."[2] More specifically, it is our understanding that Navigant intends to utilize population data, as well as historical energy consumption and historical energy savings data from past programs in order to understand the overlap and savings potential.

Lancaster and MCE question whether a top-down approach will be able to provide valuable feedback on savings potential to CCAs. For example, MCE's service area is very different than Pacific Gas and Electric Company's ("PG&E's") entire service area in terms of population demographics and climate zones.[3] Likewise, Lancaster's service area is very different than that of

[1] 2019 Potential and Goals Study Workshop, January 11, 2019.
[2] PowerPoint Presentation, *2019 Potential and Goals Study Workshop*, at 30.
[3] MCE provides retail electricity generation services to customers in Marin County, Napa County and unincorporated Contra Costa County, as well as the cities of Richmond, San Pablo, El Cerrito, Walnut Creek, Lafayette, Concord, Martinez, Oakley, Pinole, Pittsburg and San Ramon and the towns of Danville and Moraga. MCE also serves the city of Benicia in Solano County.

Southern California Edison's ("SCE's").[4] Even if Navigant examined population and historic programs savings data, a top-down allocation approach will not provide the level of detail that is required to accurately assign EE potential and savings to CCAs and RENs. For example, the potential and impact of installing a heating, ventilation, and air conditioning ("HVAC") EE measure in MCE's service area will be very different than installing that same measure in the Central Valley. Therefore, a pure allocation methodology would likely be inaccurate. Furthermore, CCAs and RENs have historically been given a limited scope under the EE programs to avoid overlap with IOU programs, including administering EE programs in fewer sectors. Historical savings information will therefore be skewed to a much greater potential for IOU programs relative to non-IOU programs.

With respect to the proposed "top-down" approach, Lancaster and MCE believe that it would be helpful to understand how Navigant is determining its population for IOU versus CCA allocations. For example, it is unclear whether Navigant is actually counting CCA customers and IOU customers in the CCA's service areas, or if Navigant is simply considering all customers in the CCAs' service areas as "CCA customers." The application of this information to establish goals is also complicated because some CCA EE programs are delivered only to CCA customers while others are available to all customers (i.e., CCA and IOU customers in the CCA's service area) and the same may be true for IOU programs.

In summary, Lancaster and MCE support modifications to the Navigant Study to improve the value to CCA programs. This study should attempt to provide the same quality and character of information for use in designing CCA programs as it does for IOU programs. Lancaster and

[4] Lancaster is a community of approximately 160,000 residents located in northern Los Angeles County, in the High Desert region of the western Mojave Desert.

MCE will be available to Navigant staff to discuss the content of these comments and opportunities to further refine the potential and goals study.

C. Response to Question #6: No Changes to the September 2019 ABALs Are Required Due to the Navigant Study

Question # 6 of the Ruling states:

> "Given the changes in potential for 2020, should there be any changes to the required components of annual budget advice letters (ABALs) due from the PAs in September 2019, and/or to the process or criteria for reviewing the September 2019 ABALs (Sections 7.2 and 7.3 of D.18-05-041)? Explain why or why not. Any recommendations in response to this question should focus on new ideas and not repeat recommendations previously made and that the Commission has already dismissed."[5]

MCE and Lancaster do not believe that there should be any changes to the required components, process or criteria for reviewing the September 2019 ABALs for all PAs. As pointed out above, energy savings goals for CCAs (and RENs) are currently *not* determined through the Navigant Study.[6] Updating the ABAL process for all PAs based on the results of the Navigant Study would therefore be partial and premature. MCE and Lancaster also believe that updating the ABAL process for just the IOU PAs would be confusing and disruptive to the EE marketplace.

III. CONCLUSION

MCE and Lancaster thank the Commission for its consideration of these comments on the Navigant Study. MCE and Lancaster look forward to continuing to work with the Commission,

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[5] Ruling at 5.

[6] MCE establishes its energy savings goals for its service territory through approval of its EE Business Plan, which the Commission approves. The current MCE Business Plan was approved in Decision ("D.")18-05-041, *Decision Addressing Energy Efficiency Business Plans*, May 31, 2018. Similarly, Lancaster provided its projected energy savings via Advice Letter and the Commission approved Lancaster's budget in Resolution E-4917. Unlike MCE, Lancaster's budget is constrained by the funding determination provided in D.14-01-033. Therefore, even if Navigant estimated potential for Lancaster's territory, the goals could not be directly derived from that number.

Navigant and other stakeholders in order to ensure that CCA programs and their customers are given appropriate and careful consideration through the course of this proceeding.

May 21, 2019

Respectfully Submitted,

/s/ Laura Fernandez

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

Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues.	Rulemaking 13-11-005

COMMENTS OF MARIN CLEAN ENERGY ON MARKET TRANSFORMATION WORKING GROUP REPORT

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May 6, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues.	Rulemaking 13-11-005

COMMENTS OF MARIN CLEAN ENERGY ON
MARKET TRANSFORMATION WORKING GROUP REPORT

Marin Clean Energy ("MCE") submits the following comments in response to the *Administrative Law Judge's* ("ALJ") *Ruling Seeking Comment on Market Transformation Working Group Report* ("Ruling") filed April 10, 2019. In the sections below, MCE provides responses to some of the questions posed in the ALJ's Ruling.

1. Please comment on the overall energy efficiency market transformation framework suggested in Attachment A and other consensus recommendations in the report. Should the Commission adopt this framework? Why or why not?

MCE largely supports the Market Transformation Working Group's ("MTWG") market transformation ("MT") framework proposal. The framework is a well-designed process to more clearly define market transformation initiatives ("MTI") and how they can complement and integrate with other energy efficiency ("EE") programs. The framework should be utilized, as drafted, to identify MTIs and then to work with all existing EE program administrators ("PAs")[1] to integrate MTIs into EE business plans. The framework should not however, be utilized to separate all EE measures that are deemed to be MTIs into their own set of separately funded, tracked and administered programs. Integrating MTIs

[1] Existing PAs include MCE and various Regional Energy Networks ("RENs") in addition to the IOU PAs.

into general EE programming will help programs trend toward more holistically integrating demand response, building decarbonization and other demand-side programs into EE programming. Such an outcome will result in a better customer experience and less challenges associated with siloed programs.

The MT administrator's ("MTA") primary function should be to coordinate with all EE PAs to ensure that MTIs are properly incorporated into EE portfolios, similar to the manner in which codes and standards ("C&S") initiatives are currently integrated within individual PA business plans but are separately tracked and reported on for cost effectiveness. The MTA's role in coordinating MTIs should be similar to the roles for statewide EE program administrators, wherein one administrator leads each statewide program, but various implementers effectuate it.[2] Like the statewide administration model, it should be a consultative and collaborative process.[3]

2. What concerns, if any, do you have about the market transformation framework as proposed in the MTWG report? What aspects would you modify? What aspects would you keep?

While not entirely clear from the MTWG report, MCE would be concerned to the extent that MTIs are designed as separately implemented EE programs that are removed in whole or in part from existing PA programs. As discussed above, MCE believes the MTWG framework allows for coordination by a single statewide MTA (or multiple MTAs) that coordinates with individual PAs to incorporate MTIs into EE portfolios. Many of MCE's existing resource acquisition ("RA") programs are already designed with MT concepts and goals in mind. Siloing these efforts from the broader set of EE offerings may

[2] D.16-08-019 at pp. 51-52.
[3] *Id*. at p. 54

undermine their impact and risk fragmenting savings opportunities. It is important to ensure that MT efforts are designed to complement, and not to eliminate or disrupt, PA's cost-effective programs already in place.

The MTWG Report contemplates,

> [S]hould a RA program need to be "ramped down" to avoid interfering with an MTI, the MT Plan should contain an estimate of the reduced Rolling Portfolio savings goal and lowering of the Total Resource Cost test (TRC) that would result from removing the savings potential of the RA programs impacted by the MTI.[4]

While MCE agrees that savings goals and TRC expectations would need to be modified in this situation, the goal should be to *avoid* ever having to "ramp down" an existing RA program in favor of an MTI. Indeed, it may be appropriate for a MTI to help fund and leverage an RA program for the success of the MTI. As MTIs are considered for approval, any potential disruptions to RA programs should be mitigated to the greatest extent possible prior to approving the MTI. Such an approach will help preserve the ability for EE programs to deliver comprehensive offerings that achieve the state's energy savings goals.

Further, it is critical that the Commission consider the impact that any disruptions to existing PA portfolios could have on the larger California EE market. As EE PAs utilize more and more third parties for program implementation, EE portfolios are increasingly founded on contracts with independent implementers. If the MT framework serves to remove rather than complement activities from RA programs, such contracts could be at risk and such uncertainty could unintentionally harm the EE industry in California. In adopting an MT framework, the Commission should be very cautions to avoid disruptions

[4] Administrative Law Judge's Ruling Seeking Comment on Market Transformation Working Group Report ("Ruling"), filed on April 10, 2019, at p. A-20.

to PA portfolios and the third-party implementers whose business models depend on that structure. Integrating MTIs into existing EE portfolios - as opposed to keeping them separate - helps address this concern. Furthermore, in the evaluation phase, all proposed MTIs should not only identify potential disruptions to existing RA programs in general, but also specifically point out the impacts on the underlying contracts with third-party implementers.

MCE is also somewhat concerned about the potential impact of the framework proposal on individual PA staff resources. For example, the report outlines a process similar to the Joint Cooperation Memos ("JCM") that the MTA would have to negotiate with each PA. Further, potential dispute resolution processes could be cumbersome and time intensive if issues between MTIs and RA programs arise. Finally, coordination and communication will be required to ensure that all PAs would be able to make the appropriate adjustments to their annual budget advice letters ("ABALs") if needed. These staffing resource issues for existing PAs can be minimized to the extent that the MTA takes on responsibility to facilitate coordination, identify conflicts and proactively design plans to avoid such conflicts so that MT efforts are minimally disruptive to PA activities. This topic is discussed further in response to question 8, below.

3. **Comment specifically on your preferred resolution of the first non-consensus issue identified in Attachment A (see pages 24-31) with respect to the appropriate choice for Market Transformation Administrator. Parties may also propose other alternatives, if there are administrative models that were not discussed in the report, but should be considered.**

To address several of MCE's concerns, and for many of the reasons stated in the MTWG Report, MCE supports the option of a single, independent statewide administrator. A single MTA is the most logical choice for effectively implementing MTIs, which are typically focused on more regional (or even national) upstream and midstream initiatives. The Commission has already recognized that upstream and midstream programs focused on market transformation should be administered by a statewide entity rather than an IOU.[5]

Further, an independent statewide, non-IOU MTA avoids any conflicts with regard to the administration of current EE portfolios, especially where IOU and non-IOU PAs have overlapping footprints. Putting IOUs in charge of all MT activities puts them in a position to be able to design MTIs that could interfere with or undermine other PA's RA programs (*e.g.* shaving off the most cost-effective initiatives into a separate MTI portfolio). A single statewide MTA would operate under the guidance to avoid and mitigate disruption to all RA programs and all EE PAs would be aligned in limiting such disruptions. Such a structure would help ensure EE activities are successful and that MTIs are used as a tool to bolster, rather than interfere with, individual PA portfolios.

4. Comment specifically on your preferred resolution of the second non-consensus issue identified in Attachment A (see pages 36-38) with respect to the cost-effectiveness threshold that should be required for market transformation initiatives? Parties may also propose other alternatives.

MCE supports Option 1 of the proposed cost effectiveness thresholds - to utilize the same threshold in the MT context as is applied to the general EE context. As noted in the MTWG Report, a 1.25 TRC per MTI is a more exacting standard than the 1.25 portfolio-wide standard applied to EE Rolling Portfolios.[6] Further, setting the cost effectiveness standard at the same levels for both MTIs and Rolling Portfolio programs helps to prevent the possibility that the most cost-effective measures are picked off from

[5] Decision Providing Guidance for Initial Energy Efficiency Rolling Portfolio Business Plan Filing ("D.16-08-019"), filed on August 25, 2016, at pp. 57-59.
[6] Ruling at p. A-47.

the Rolling Portfolio programs. However, as noted above, a framework that emphasizes integration of MTIs into Rolling Portfolios would further mitigate this issue, rather than creating separate MT portfolios that would compete for cost effectiveness.

5. **To what extent can current cost-effectiveness tools and methods fully evaluate market transformation initiatives that would result in codes and/or standards? If current methods are insufficient, please comment on the two options outlined on page 35 of Attachment A, and include any other recommendations on this topic.**

MCE has no comments on this issue at this time.

6. **Should a budget allocation to market transformation be incremental to the rolling portfolio budgets, or should a portion of the energy efficiency rolling portfolio budgets be redirected to market transformation? Why?**

Consistent with the goal of creating minimal disruption to existing RA programs, MT budgets should be incremental to Rolling Portfolio budgets. To the extent that MTAs focus their efforts on identifying MTIs that can successfully be added to existing Rolling Portfolios, the funding for such additional measures should be supported from MT-specific budgets. This allows existing program budgets to continue as approved and without disruption.

7. **How much should the initial funding allocation be for market transformation, and for what duration?**

MCE has no comments on this issue at this time.

8. **How should the coordination between resource programs and market transformation initiatives be managed? Would a cooperation agreement between market transformation initiatives and resource programs be useful?**

As explained in the above introductory section and in MCE's response to questions 1 and 3, a single statewide MTA whose role focuses on the coordination and integration of MTIs into existing RA programs (*e.g.* similar to C&S programs) would help to more comprehensively address program overlap. Part of the single statewide MTA's function should include the development and facilitation of cooperation agreements or JCMs. However, to address MCE's concerns stated above[7] regarding the potential demand on staff time and resources, the Commission should consider requiring MTAs to develop master JCMs with each Rolling Portfolio PA before a portfolio of MTIs is selected, rather than having to constantly develop JCMs for each individual MTI. The master JCM should be updated annually to incorporate changes to RA programs and rules.

Another strategy to avoid disruptive overlap would be to adopt the MTWG's recommendation to select MTIs that enhance positive and minimize negative overlap.[8] MCE agrees that the MTA and MT advisory board ("MTAB") should develop specific criteria that would quantify the degree of negative overlap that a proposed MTI would create.[9] Only MTIs that fall below an established threshold should be considered for adoption.

The MTAB should play a pivotal role in preventing negative overlap and ensuring that the MTA is sufficiently coordinating with all relevant stakeholders. As such, it is important that all EE PAs have the opportunity (but are not required) to participate in MTAB meetings and provide input, even if such entities are not actually on the MTAB. In order to promote transparency and allow interested PAs to participle in MTAB meetings, the Commission should require the MTAB to provide at least two-weeks of notice of any meetings. Additionally, proposed agendas should be shared with stakeholders through the California Energy Efficiency Coordinating Committee ("CAEEC"). This will help to

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[7] *See*, MCE response to question 2 at p. 4.
[8] Ruling at p. A-52.
[9] *Id.*

ensure that implementors, PAs, and other stakeholders with concerns about program overlap are able to attend and help resolve conflicts.

9. Once a market transformation initiative is approved, what should be the process for updating or amending key terms (e.g., metrics, milestones, targets, schedules, and savings methodologies) during implementation?

MCE has no comments on this issue at this time.

10. If a market transformation initiative, once approved, begins to perform poorly:

a. How will the Commission become aware there is a problem?

b. What should the process be to determine if a market transformation initiative with questionable performance should be amended or terminated?

MCE has no comments on this issue at this time.

11. The MTWG report references "financial commitments to the target market(s)" (see page 17) and a market transformation plan that "solidifies a commitment to the market and relevant actors" (page 18). What kinds of commitments should a market transformation initiative make to the market(s) and market actors? What kinds of commitments are not appropriate, if any?

MCE has no comments on this issue at this time.

12. Are there other issues not addressed in Attachment A that the Commission should consider as part of its decision establishing a framework for energy efficiency market transformation?

MCE has no additional comments at this time.

CONCLUSION

MCE thanks ALJ Fitch, ALJ Kao and Commissioner Randolph for their thoughtful consideration of these comments.

Respectfully submitted,

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May 6, 2019

KEYES&FOX LLP

May 8, 2019

CPUC Energy Division
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Re: Joint CCAs' Protest to Pacific Gas and Electric Company ("PG&E") Advice Letter 5527-E

Dear Tariff Unit and Mr. Randolph:

By way of this letter, submitted pursuant to General Order 96-B, East Bay Community Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Silicon Valley Clean Energy, and Sonoma Clean Power, (collectively, the Joint Community Choice Aggregators ("Joint CCAs")) jointly protest Pacific Gas & Electric Company ("PG&E")'s Advice Letter 5527-E ("Advice Letter").[1]

Decision ("D.") 19-02-023 (the "Decision" or "ERRA Decision") ordered PG&E to calculate a first-of-its-kind true-up of the brown power market price benchmark ("MPB") for 2018, recognizing a more complete true-up of other market components will be implemented for the following years through the Portfolio Allocation Balancing Account ("PABA").[2] The interim methodology the Commission required for the 2018 true-up simply replaces the forecasted market value and generation quantities of brown power and ancillary services with the actual value and quantities.[3] The resulting incremental indifference amount for each vintage is then converted to a refund/charge rate using the top 100 hours allocation factors and system forecasted load.[4] The refund/charge is subtracted from the Power Charge Indifference Amount ("PCIA") rate adopted in D.19-02-023 for each class and vintage, resulting in the final PCIA rates for 2019.[5]

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1 General Order ("GO") No. 96-B §7.4.2.
2 D.19-02-023 at 26-27.
3 *Id.* at Ordering Paragraph ("OP") 5.
4 *See id.* at 21-22, OP 4.
5 *See id.* at 21-22, OP 4.

I. Summary of Protest

The Advice Letter fails to follow the Commission's directives for this first true-up. Rather than strictly following D.19-02-023, PG&E calculates the incremental indifference amount using actual values for generation costs— an approach the Commission just rejected in Southern California Edison's ("SCE's") advice letters 3972-E and 3972-E-A, which implemented SCE's version of the brown power true-up ("BPTU").[6] PG&E also uses the actual quantities for Renewable Portfolio Standard ("RPS")-eligible energy, inappropriately modifying the market value of the green benchmark. Further, PG&E includes the market price of RPS resources in its calculation of the actual market price of non-RPS resources, skewing the overall average price used to calculate the BPTU. PG&E also applies the cumulative refund rate to all of the vintages prior to 2018, but it pro-rates the 2018 vintage, applying an unauthorized, unjust and unreasonable methodology that has never been applied before or scrutinized in a proceeding where the questions of fact it raises can be tested.[7] Finally, PG&E overlooks the value of self-scheduled ancillary services, only including the cost of providing those services in its BPTU.

The Joint CCAs, therefore, protest the Advice Letter on the grounds it:

1. Includes components and follows methodologies not authorized by D.19-02-023;
2. Commits material errors when calculating both the Incremental 2018 Indifference Amount and the resulting refund rate;
3. Results in unjust and unreasonable rates; and
4. Inappropriately requests the adoption of new policy in a Tier 2 advice letter process intended to address "ministerial" actions for which hearings are not required.[8]

We respectfully request this protest be granted and PG&E required to file a supplement to the Advice Letter calculating the true-up in strict compliance with D.19-02-023, utilizing forecasted

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[6] Energy Division, *Non-Standard Disposition Letter re Southern California Edison Advice Letters 3972-E and 3972-E-A -- 2019 Energy Resource Recovery Account Forecast Proceeding Revenue Requirement in Accordance with D.19-02-024*, pp. 1, 4 (April 20, 2019) ("SCE Disposition Letter").

[7] PG&E Response to Joint-CCA_002-Q01(e) (See Attachment B to this Protest).

[8] GO 96-B §§ 5.1, 7.4.2(2), (3), and (6).

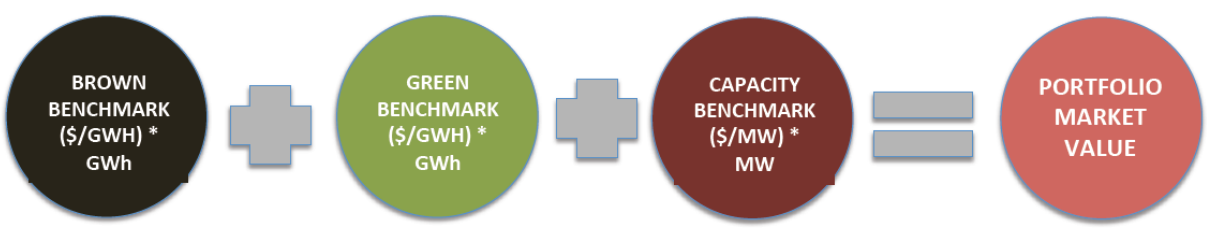
generation costs, maintaining the forecasted RPS quantities, calculating a brown power-only market price, removing the pro-rated treatment for the 2018 vintage, and valuing self-scheduled ancillary services. This approach will not only closely follow D.19-02-023 but also ensure alignment between departed customers in PG&E and SCE's service territories.[9]

The Joint CCAs have attached workpapers and resulting rates enacting changes to correct PG&E's errors using data from PG&E's discovery responses and workpapers.[10] Per those calculations, the correct BPTU will be a net refund to unbundled customers of $163.8 million (plus the value of self-scheduled ancillary services) rather than the $36.3 million figure included in the Advice Letter.[11]

II. PG&E's Calculation of the Brown Power True-Up Includes Unauthorized Components that Result in Material Errors and Unjust and Unreasonable Rates.

The Commission requires the PCIA to be calculated based on an indifference amount determined by forecasts of total portfolio costs and market value, as shown below:

The Portfolio Market Value (the middle circle in the equation above) is made up of the following three components:



Ordering Paragraph 5 in D.19-02-023 sets forth the methodology for implementing the 2018

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9 SCE Disposition Letter at 4.

10 *See* Attachment A to this Protest.

11 PG&E Advice Letter 5527-E, p. 8 and Appendix A (April 18, 2019) ("Advice Letter").

BPTU:

> The 2019 forecast shall include a true-up of the 2018 forecast year for brown power. Pacific Gas and Electric Company is ordered to calculate the true-up by applying actual 2018 market prices to actual PCIA-eligible generation deliveries and realized Ancillary Services revenues in accordance with D.18-10-019. Subsequently, the Renewable benchmark will be updated per Resolution E-4475 when adjusting the Brown Power Benchmark.[12]

The Commission's approach requires PG&E to subtract the Revised 2018 Indifference Amount (based on implementing the BPTU) from the Original 2018 Indifference Amount (used to establish the original 2018 PCIA rate approved in D.18-01-009) to arrive at an Incremental 2018 Indifference Amount, as shown below:[13]

To derive the Revised 2018 Indifference Amount, the Commission required PG&E to adjust the *benchmark* for actual market *revenues* via "actual 2018 market prices" and "realized Ancillary Services revenues,"[14] with those "determined by the net of [California Indepdendent System Operator ("CAISO") revenues for PCIA-eligible resources."[15] "For the purposes of the 2018 brown power true-up, net CAISO revenues correspond to the sum of revenues and charges" associated with 43 different CAISO charge codes, which PG&E lists in a response to a Joint CCAs' data request, and none of which constitutes generation costs.[16] The benchmarks within the PCIA calculation only modify the Portfolio Market Value, meaning an adjustment to the brown power benchmark should not adjust actual generation costs.[17] The new portfolio market value, which might be termed an "Actual Portfolio Market Value", results in a Revised 2018

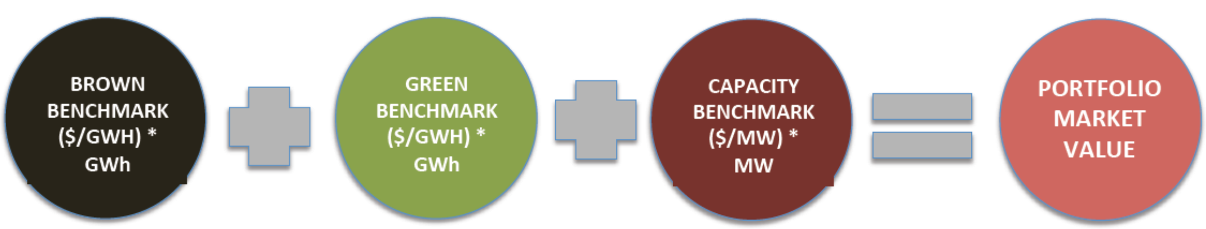
12 D.19-02-023 at OP 5.
13 Advice Letter at 8.
14 D.19-02-023 at OP 5.
15 *Id.* at 21, n. 31; *see also id.* at Conclusion of Law 5 (stating "A true-up of brown power in the 2019 ERRA Forecast based on 2018 actual net CAISO revenues for PCIA-eligible resources complies with D.18-10-019.").
16 PG&E Response to Joint-CCA_002-Q06(a) (See Attachment B to this Protest).
17 *See, e.g.*, A.18-06-001, Exh. PG&E-1, Table 9-4.

Indifference Amount, as follows:

PG&E must then allocate the resulting, Incremental 2018 Indifference Amount for each vintage to departed customers in the same manner as the original indifference amount is allocated, *i.e.*, by the top 100 hours allocation factors and then by dividing by system load, in order to arrive at refund/charge rate for each rate class in each vintage.[18] The refund/charge rate is then subtracted from the PCIA rate adopted in D.19-02-023 for each class and vintage, resulting in the final PCIA rates for 2019.[19] However, the Advice Letter does not follow the required approach.

PG&E's approach to calculating the Revised 2018 Indifference Amount departs substantially from D.19-02-023 by including actual generation costs and actual quantities to calculate a revised version of Total Portfolio Costs.[20]

Second, PG&E uses actual quantities for calculating both the brown benchmark *and* the green benchmark, modifying the "GWh" quantities in both the first circle and the second circle below:



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18 *See* D.19-02-023 at 21-22, OP 4.

19 *See id.*

20 Advice Letter at 7.

Third, PG&E reports a cumulative brown power price for each vintage in an aggregated, non-resource-specific manner.[21] As stated in a discovery response, "[h]ourly generation (MWh) by individual resources were not used as part of the 2018 true-up analysis. The CAISO generation data PG&E used in calculating the brown power true-up were obtained from the CAISO settlement system using a database script that aggregated CAISO generation by resource, month and CAISO market (Day Ahead or Real-Time)." [22] As a result, resources included in the actual market price calculation for non-RPS power are from all resource types, *including* RPS resources (which are explicitly excluded from the BPTU process). Because the different generation profile of RPS resources results in a different market value, the overall average price used to conduct the true-up is skewed.

Because the Actual Total Portfolio Cost in PG&E's formula ($5.19 billion) is greater than the original Forecasted Total Portfolio Cost ($5.13 billion) by approximately $54 million,[23] and because the actual GWh output in 2018 (67.727 GWh) is lower than the forecasted GWh output in 2018 (70,830 GWh), PG&E's approach lowers the revised indifference amount to the unjust benefit of its bundled ratepayers and detriment of unbundled ratepayers.[24]

A. The Inclusion of Actual Generation Costs is Unauthorized and Constitutes a Material Error in Determining the Incremental Indifference Amount.

To justify its approach, PG&E's Advice Letter states that "to perform such a true-up *requires* PG&E to consider vintaged brown power costs…." [25] No such requirement exists. The market prices used to determine the Actual Portfolio Market Value can be derived in a verifiable manner using available CAISO data without considering generation costs. In fact, this is exactly what SCE did in its advice letters to calculate its BPTU amount.[26] The Joint CCAs have

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[21] Advice Letter at 7-8; PG&E Response to Joint-CCA_001-Q06 (See Attachment B to this Protest) (stating "the CAISO settlement system calculates the revenues/charges (i.e., the CAISO multiplies the CAISO market prices by the CAISO scheduled generation). PG&E directly queried the CAISO determined revenues/charges from the CAISO settlement system" in determining its BPTU).

[22] PG&E Response to Joint-CCA_002-Q02 (See Attachment B to this Protest).

[23] Advice Letter at Appendix B.

[24] *Id.* at Appendix C.

[25] *Id.* at 5 (emphasis added).

[26] *See* Southern California Edison, Advice Letter 3972-E, Appendices B and C.

completed such an analysis as part of its attached workpapers, using data provided by PG&E.[27]

PG&E also relies heavily on the phrase "in accordance with D.18-10-019" in the ERRA Decision to support the idea that "within the limitations of not having yet established the PABA framework" its true-up "complies with the direction provided in D.19-02-023, including the references to D.18-10-019."[28] PG&E's argument amounts to a suggestion that D.19-02-023 allows the utility to include any true-up components from Ordering Paragraph ("OP") 7 or elsewhere in D.18-10-019 as long as those components can be calculated today.

Energy Division recently rejected this same argument from SCE, which had suggested "what is known and achievable now related to brown power costs and market values should be trued up now."[29] Applying language in D.19-02-024 (SCE's ERRA decision) that is nearly identical to that within D.19-02-023,[30] Energy Division approved "the brown power true-up as ordered in [D.19-02-024], utilizing a strict reading of the decision and only implementing the true-up as explicitly approved therein."[31] Under such a strict reading, Energy Division concludes "SCE was ordered to update the market value of its energy portfolio for 2018, but was neither permitted nor instructed to update *any* of its generation costs."[32]

PG&E's ERRA Decision likewise does not allow the Advice Letter's approach. The references in D.19-02-023 to the PCIA Decision are to OP 7,[33] which PG&E continues to misapply.[34] OP 6 in D.18-10-019 requires the IOUs to "annually true-up their PCIA rates to reflect actual values realized in market transactions for the subject year for the Brown Power

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27 *See* Attachment A to this Protest.
28 PG&E Response to Joint-CCA_001-Q07 (See Attachment B to this Protest).
29 SCE Responses to SoCal CCAs' Protests of Advice Letter 3972-E, pp. 2-3 (March 25, 2019).
30 SCE Disposition Letter at 1 and 4 (citing D.19-02-024 at 35); *compare* D.19-02-023 at p. 21 and OP 5 *to* D.19-02-024 at p. 35 and OP 7.
31 *Id.* at 2.
32 *Id.* at 4 (emphasis in original).
33 Advice Letter at 5, n. 10 (citing to "D.18-10-019, OP 7 at 161").
34 *See* A.18-06-001, PG&E Opening Comments on Alternate Proposed Decision, p. 4 (Feb. 11, 2019).

Index."[35] OP 7 sets the stage for the *future* evolution of the true-ups conveying the Commission's intent to true up RA and RPS-eligible resources at a later date:

> [The utilities] shall each file a Tier 2 Advice Letter within 60 days to establish a Portfolio Allocation Balancing Account (PABA) with subaccounts for each vintaged portfolio to account for billed revenues, generation resource costs, net California Independent System Operator market revenues associated with energy and ancillary services, and revenues associated with the renewable energy Adder and the Resource Adequacy capacity in each vintaged portfolio.[36]

While OP 7 includes the phrase "generation resource costs", it clearly links that phrase to the RPS adder and the Resource Adequacy ("RA") capacity adders in the context of the PABA, which PG&E acknowledges has not yet been approved.[37] In fact, it is not possible to include many of the components listed in OP 7 within the true-up at this time. For example, PG&E acknowledges in a discovery response that it left out "billed revenues" from its calculation of the true-up because "a system for tracking that information did not exist for 2018." [38]

D.19-02-023 clearly establishes an *interim* approach for 2018 that only includes "applying actual 2018 market prices" and "Ancillary Services revenues."[39] The Commission expressly rejected an approach that includes more, recognizing that a formal recorded account for other market transactions "did not exist for all of 2018," and, "[f]or this reason, we are directing PG&E to follow a calculation methodology that offers the most transparency and least controversy regarding verifiability of values and how they are applied in the PCIA template."[40] If the Commission were to accept the argument that the phrase "in accordance with D.18-10-019" meant the utility may include any true-up component listed in OP 7, or elsewhere in that

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35 D.18-10-019 at OP 6 (emphasis added).

36 *Id.* at OP 7.

37 Advice Letter at 5-6.

38 PG&E Response to Joint-CCA_001-Q07 (See Attachment B to this Protest). However, the Joint CCAs note that PG&E erroneously states that bundled customers do not pay the PCIA. In fact, the PCIA rate is calculated by dividing the Indifference Amount by the total (bundled plus departed) customer load. This calculation means that all customers pay this charge, but it is shown only as a line item on departed customers' bills. For bundled customers, it is embedded in the total generation charge component just as many other separate costs (e.g., resource adequacy and fuel costs) are bundled into it.

39 D.19-02-023 at OP 5.

40 *Id.* at 26-27.

decision, it would be tacitly allowing a true-up that includes components like the RPS and RA adders the Commission clearly concluded should be out of scope of the 2018 true-up.

Like SCE, PG&E must apply the Commission's interim approach in strict accordance with the methodology D.19-02-023 prescribes. That methodology only authorizes a true-up of forecasted market prices and actual market prices, and the Advice Letter's inclusion of actual generation costs constitutes a material error.[41] Modifying PG&E's approach to correctly implement D.19-02-023 by removing the changes made to include actual generation costs adds $111.8 million to the incremental indifference amount, *i.e.*, the gross true-up refund that is owed to unbundled customers.

B. The Inclusion of Actual Quantities to Calculate the Green Benchmark is Unauthorized and Constitutes a Material Error in Determining the Incremental Indifference Amount.

Another problem within the Advice Letter is PG&E's adjustments to the quantity values associated with the green benchmark. The amount of RPS generation in PG&E's 2017 November Update, which the Commission adopted, was 18,929 gigawatt-hours ("GWh"). The amount of RPS generation in PG&E's workpapers for the true-up is 18,604 GWh. This means PG&E revised its RPS generation numbers, thus inappropriately modifying the RPS benchmark.

PG&E's methodology of truing up the *brown* benchmark with actual quantities for the *green* adder should be rejected. OP 5 in the ERRA Decision requires PG&E to include actual quantities from non-RPS generation when calculating the BPTU, stating that the "2019 forecast shall include a true-up of the 2018 forecast year for brown power" utilizing "actual PCIA-eligible generation deliveries."[42] While the Commission allowed PG&E to adjust the RPS benchmark in the ERRA Decision, that permission was limited to the extent updating the brown benchmark, which forms part of the RPS benchmark calculation, changes the RPS benchmark.[43] Adjusting the actual quantities for the renewable benchmark goes beyond the brown power-

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41 GO 96-B §7.4.2(2), (3).

42 D.19-02-023 at OP 5.

43 D.19-02-023 at 21, n. 33 (citing Resolution E-4475, Exhibit A), and OP 5. Exhibit A of Resolution E-4475 demonstrates how 32% of the green benchmark is calculated by adding the "DOEadder" to the brown benchmark.

related changes the Commission authorized.[44]

The Commission never authorized the use of actual RPS quantities and doing so results in material errors and unjust and unreasonable rates. Apart from modifications to the brown benchmark underlying it, only forecasted values should be used for calculating the green benchmark. Modifying PG&E's approach to utilize forecasted rather than actual quantities, *i.e.*, to implement D.19-02-023 correctly, adds $2.9 million to the value of the BPTU. This value is already included in the value above in the previous section regarding the use of forecasted costs.

C. PG&E Incorrectly Calculated the Market Price of Brown Power, Which Constitutes a Material Error in Determining the Incremental Indifference Amount.

Finally, PG&E should have not utilized aggregated, non-resource-specific generation data that failed to distinguish between brown power and RPS-eligible energy. In both the body of the decision and in OP 5, the Commission's directives regarding the true-up are couched in terms of brown power.[45] Reading the Commission's directives to include green power prices to update brown power prices is unauthorized and should be rejected. As noted in the previous section, the Commission limited allowed changes to the RPS benchmark to those implicitly created by modifying the brown benchmark—not the inclusion of RPS prices in non-RPS prices.[46]

Further, PG&E's approach is contrary to how the PCIA itself calculated, where the brown benchmark is multiplied by the forecasted amount of non-RPS energy, and the green benchmark is multiplied by the forecasted amount of RPS energy.[47] Thus, no authority exists to support PG&E's change to establish actual non-RPS prices using RPS prices. Removing RPS prices from the brown power calculation increases cumulative market prices by approximately

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44 *Id*. *See also* Resolution E-4475, Exhibit A (only addressing "forecasted deliveries," and not actual deliveries).

45 *See* D.19-02-023 at 21, OP 5.

46 *Id.* at 21, n. 33 (citing Resolution E-4475, Exhibit A), and OP 5. Exhibit A of Resolution E-4475 demonstrates how 32% of the green benchmark is calculated by adding the "DOEadder" to the brown benchmark.

47 *See* A.18-06-001, Exh. PG&E-1, Table 9-4; *see also* Advice Letter at Appendix B, Exhibit 1, lines 12 and 16.

$5/MWh and results in an addition of $59.7 million to the value of the brown power true-up.[48]

III. The Commission Did Not Authorize PG&E's Treatment of the 2018 Vintage.

The second major problem with the Advice Letter is PG&E's derivation of the refund rate for the 2018 vintage, which implicitly proposes a new policy that is unjust and unreasonable. PG&E states: "For the 2018 vintage load, the overpayment amount in 2018 is determined by multiplying the refund rate times the actual sales for this vintage. The resulting PCIA overpayment is used to derive the applicable refund rate."[49] This explanation is murky and circular in its logic, essentially saying the utility uses the refund rate to determine the overpayment amount to determine the refund rate.[50]

In practice, PG&E pro-rated the refund rate for the 2018 vintage. Rather than apply the cumulative 2018 true-up rate to the 2018 vintage sales forecast as they did for all other vintages, PG&E multiplied the cumulative 2018 true-up rate by the ratio of actual 2018 vintage sales to forecasted 2018 vintage sales. As an example, the cumulative 2018 vintage true-up rate for residential customers is $0.00183/kWh.[51] PG&E scaled that down by the ratio of actual 2018 sales to 2019 forecasted sales for 2018 vintage customers: 846 GWh / 4,729 GWh = 17.9% * $0.00183 = $0.00033/kWh.[52]

PG&E's calculation reduces the refund paid to 2018 vintage departed customers during 2019 based on their actual sales in 2018 after leaving PG&E's system. The system average refund rate for the 2018 vintage is $0.00020/kWh.[53] For comparison, the system refund rate for all other vintages averages to $0.00144, over *six times greater* than the refund rate for 2018.

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48 PG&E calculated the actual 2018 brown power benchmark as the actual CAISO net revenue for all PCIA resources, including RPS resources, divided by the GWh generation from those resources. PG&E provided the net revenue and GWh generation by resource in worksheet 6 of its workpapers supporting Appendix B, Exhibit 2. The Joint CCAs used the PCIA resource categories provided in PG&E's worksheets 4 and 5 to identify individual RPS resources in worksheet 6 and remove them from the brown power benchmark calculation, resulting in an actual 2018 brown power benchmark of $45.05/MWh for non-RPS resources.

49 Advice Letter at 8.

50 *Id*.

51 *See id.* at Appendix C, p. 6 and associated workpapers.

52 *See id.* at Appendix C, pp. 6-7 and associated workpapers.

53 *Id.* at Appendix C, p. 6.

Overall, the approach effectively eliminates $15.7 million of the BPTU refund, an amount that inappropriately flows to PG&E's bundled customers.

PG&E's methodology appears to be motivated, in part, by the timing of load departures during 2018. The utility states it calculated the true-up "*pro rata* based on the amount of customer sales contributing to the 2018 over-collection."[54] PG&E reasons that customers leaving PG&E's system during 2018 would have paid the 2018 PCIA rate for only a portion of the year and, therefore, "[a]pplying the full adjustment to all 2018 vintage customers would lead to an inequitable outcome." [55]

This reasoning and the resulting, newly proposed methodology should be rejected on both substantive and procedural grounds. First, it denies a refund to customers that should receive one. As has been well established within the ERRA forecast proceedings, both bundled and unbundled customers pay for the above-market costs of PG&E's portfolio. This means that customers departing mid-year pay any above market costs first through the ERRA prior to departing and second through the PCIA after departing. EBCE's residential customers, for example, departed PG&E's service territory in November 2018, meaning they paid the bundled ERRA generation rate 11 months out of the year and the PCIA rate in December of that year. Because the 2018 PCIA forecast rates were too high, EBCE's residential customers overpaid (based on the actual market value of brown power) from January to November when they were still bundled customers, and they continued to overpay in December once they had departed. Under PG&E's reasoning, however, those customers are only be eligible for a refund for December because that is the only month in which they paid the PCIA.

The result is that even though EBCE's residential customers made the same overpayments for 11 months through the ERRA, they will not receive a true-up based on market values.[56] Instead, those refund amounts will pass through to bundled customers via the ERRA

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54 *Id.* at 8.

55 *Id.*

56 PG&E suggests in a discovery response that if some vintage 2018 departed load customers remained bundled customers, they would bear a share of some increased costs from when they were

because the ERRA does not apply to a customer that has already left PG&E's service.

Complicating PG&E's concept of equity further, different groups of customers departed at different times in 2018. MBCP's residential customers, for example, departed in July 2018, paying the ERRA half of the year and the PCIA the other half of the year. When PG&E pro rates the entire vintage regardless of actual departure dates, it effectively creates an average departure date for all customers in the 2018 vintage. This averaging results in EBCE's customers receiving more refund per kWh for their PCIA-linked sales than they otherwise would have under a more granular approach. Conversely, MBCP's customers likely are receiving less refund per kWh for their PCIA-linked sales than they otherwise would have received under a more granular approach. That is, PG&E's proposed policy chooses to take the refunds for certain customers and distribute them to other customers without any authorization from the Commission.

A much simpler approach is to apply the complete 2018 vintage true-up rate to all customers in that vintage. That approach ensures all customers that overpaid in 2018 based on the forecasted versus actual market value of brown power will receive refunds. Further, unlike PG&E's methodology, applying the complete 2018 vintage true-up rate to all customers in that vintage would comply with D.19-02-023. Therein, the Commission also stated that the Incremental 2018 Indifference Amount, *i.e.*, the "difference between the total indifference amount in the 2018 Forecast ERRA case and that calculated with the 2018 brown power true-up," must "be reflected in rates in a manner compliant with the PCIA workpapers filed in this

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bundled customers towards the end of 2018 because those costs are not included until the balancing account is applied the following year.

However, those costs are outside the scope of the PCIA true-up as only the market value of brown power is being trued up. The Commission has determined that these two accounting actions are to be separated, not conflated. *See, e.g.,* Commissioner Guzman-Aceves's concurrence to D.19-02-023, stating "The ERRA alternate decision appropriately addresses unforecasted ***revenues*** from brown power in 2018, just as companion decisions address under-collection of ***costs***, such as the SCE trigger application for 2018, Application 18-11-009" (emphasis added). Further, those costs are small in comparison to the increased market value—about 32%—since only a small portion of PG&E's fleet is natural gas fired (*i.e.*, the increase in brown power value substantially outweighs the increase in brown power costs). Those costs certainly do not warrant taking the vast majority of the BPTU (92%) for the 2018 vintage away from the departed 2018 vintage.

proceeding."[57] All of the approved workpapers in this proceeding use forecasted system sales to determine the PCIA applicable to each vintage. None have only used PCIA-linked sales to determine the PCIA rate.

Further, OP 4 of that decision states: "The calculation of the PCIA rate shall follow as it has in past ERRA proceedings by allocating the cumulative vintaged Indifference Amount to each rate group using the allocation factors *followed by dividing by the forecasted system sales for the forecast year*."[58] This same approach should apply to the true-up where the forecasted system sales for 2018 determine the refund rate, not just those sales that were subject to the PCIA.

In contrast, PG&E's approach revises the forecasted system sales figures approved in D.19-02-023 for the purpose of calculating the true-up refund. PG&E inappropriately cites D.19-02-023 to support its change, relying heavily on a passage in D.19-02-023 that includes the term "pro rata."[59] However, the passage PG&E cites is from Conclusion of Law 16 in D.18-10-019, which is where the Commission concludes adopting a BPTU is reasonable.[60] This language addresses the adoption of the BPTU as a whole, concluding that the true-up will ensure "bundled and departing load customers pay equitably (i.e., pro rata) for non-RA, non-RPS PCIA-eligible resources."[61] It does not establish a particular pro-rated methodology for implementing the true-up for a specific vintage. As PG&E admits, "[t]he ERRA Forecast decision does not explicitly address '. . . vintaging of customer sales for the 2018 vintage or any single year.'"[62]

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57 *Id.* at 21-22.

58 *Id.* at OP 4 (emphasis added); *see also id.* at Finding of Fact 9 (stating "It is reasonable to continue to calculate the PCIA rate by dividing the allocated vintaged Indifference Amount by the forecasted system sales.").

59 Advice Letter at 8.

60 D.18-10-019 at Conclusion of Law 16 (stating "A true-up mechanism for the Brown Power Index to reflect actual values realized in market transactions for the subject year should be adopted to ensure that bundled and departing load customers pay equitably (i.e., pro rata) for non-RA, non-RPS PCIA-eligible resources.")

61 *Id*.

62 PG&E Response to Joint-CCA_003-Q013 (See Attachment B to this Protest).

The Commission has never approved or considered PG&E's approach in a proceeding in which questions of fact regarding its impacts and equity can be tested.[63] PG&E attempts to write untested policy changes into a Tier 2 advice letter resulting from an ERRA forecast proceeding—the type of proceeding the Commission has emphasized time and again is not a policymaking proceeding.[64] General Order 96-B limits advice letters to "a quick and simplified review of the types of utility requests that are expected neither to be controversial nor to raise important policy questions."[65] It limits Energy Division's resolution of a Tier 2 advice letter to "ministerial actions,"[66] and states that "[t]he advice letter process does not provide for an evidentiary hearing; a matter that requires an evidentiary hearing may be considered only in a formal proceeding."[67] Thus, adopting PG&E's approach is inappropriate for a Tier 2 advice letter process.

The approach should be rejected and the cumulative 2018 true-up rate should be applied to the 2018 vintage on a 1-to-1 basis. Based on the Joint CCAs' calculations, removing the *pro rata* adjustment to 2018 rates to correctly implement D.19-02-023 increases the amount of the BPTU by $15.7 million.

IV. PG&E Excludes Self-Scheduled Ancillary Services from Market Valuation, Creating a Subsidy to Bundled Customers.

D.19-02-023 calls for the inclusion of the market value of ancillary services provided to the CAISO. The Decision makes no distinction between ancillary services that are bid into the CAISO markets and those that are self-scheduled to support other generation resources. PG&E has a substantial amount of self-scheduled ancillary services according to its workpapers filed in its 2018 ERRA Compliance application.[68]

PG&E's method of accounting for revenues and costs through the CAISO settlements

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63 PG&E Response to Joint-CCA_002-Q01(e) (See Attachment B to this Protest).

64 *See, e.g.*, D.18-01-009 at 10; A.17-06-005, *Scoping Memo and Ruling of Assigned Commissioner,* pp. 3-4 (August 24, 2017); A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner*, p. 3 (Sep. 12, 2013).

65 General Order 96-B § 5.1.

66 *Id.* at § 7.6.1.

67 *Id.* at § 5.1.

68 A.19-02-018, PG&E Filed Direct Testimony, Chapters 1 and 9 workpapers.

overlooks the value of these self-scheduled ancillary services because the CAISO does not record a financial transaction for the services provided. Yet PG&E includes the *cost* of providing those services in its BPTU. This failure to credit the value of ancillary services to the total portfolio value forces departed customers to pay a share of the costs without receiving an offsetting credit in the PCIA. As a result, departed customers are subsidizing bundled customers through the PCIA.

The correct method is for PG&E to calculate the hourly prices paid for ancillary services and then to multiply those hourly prices by the amount of the self-scheduled ancillary services. That value then should be segmented by whether the generation resource providing the service is RPS-eligible, and the non-RPS ancillary service value added to the total portfolio value as part of the BPTU.

V. Conclusion

Unlike SCE, PG&E did not provide an alternative calculation of the BPTU in compliance with D.19-02-023. For this reason and those stated above, we respectfully request the Commission grant this Protest to the Advice Letter and require PG&E to file a supplemental advice letter correctly implementing the BPTU.

Respectfully submitted,

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Service List for A.18-06-001

Pacific Gas and Electric Company
Advice 5527-E
Appendix B, Exhibits 1 - 4 Workpaper

Appendix B, Exhibit 4 (Revised)

Joint Community Choice Aggregators

2018 True-up Indifference Adjustment Calculation

Line No.	Description	Source/Equation	Unit	CTC	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Cost of Portfolio													
1	Total Portfolio Cost1	Worksheet 1, Line 3	$000	$250,757	*$4,489,366*	*$4,957,703*	*$5,137,709*	*$5,306,117*	*$5,335,014*	*$5,349,593*	*$5,361,160*	*$5,383,282*	*$5,384,740*	*$5,384,740*
2	Total Portfolio Cost Less Ongoing-CTC	Line 1 Less CTC (250,757)	$000		$4,238,609	$4,706,946	$4,886,952	$5,055,360	$5,084,257	$5,098,836	$5,110,403	$5,132,525	$5,133,983	$5,133,983
3	Supply At Customer Meter1	Worksheet 1, Line 6	GWh	3,116	*43,207*	*46,105*	*47,407*	*49,065*	*49,417*	*49,436*	*49,770*	*49,990*	*50,006*	*50,006*
4	Supply At Customer Meter Less Ongoing-CTC	Line 3 Less CTC (3,116)	GWh		40,092	42,990	44,292	45,950	46,301	46,320	46,654	46,874	46,890	46,890
5	Renewable Supply at Customer Meter1	Worksheet 4, Line 493	GWh	278	*11,038*	*15,210*	*16,466*	*18,008*	*18,359*	*18,378*	*18,693*	*18,913*	*18,929*	*18,929*
6	Renewable Supply at Customer Meter less Ongoing-CTC	Line 5 Less CTC (278)	GWh		10,759	14,931	16,188	17,729	18,081	18,100	18,415	18,635	18,650	18,650
7	Average Monthly Net Qualifying Capacity	Worksheet 1, Line 9	MW	636	10,688	11,006	11,313	11,490	11,517	12,074	12,091	12,157	12,157	12,157
8	Average Monthly Net Qualifying Capacity less-CTC	Line 7 Less CTC (636)	MW		10,052	10,370	10,677	10,854	10,881	11,438	11,455	11,521	11,521	11,521
9	**Portfolio Unit Cost**	Line 1 / Line 3	$/MWh	**$80.48**	**$103.90**	**$107.53**	**$108.37**	**$108.14**	**$107.96**	**$108.21**	**$107.72**	**$107.69**	**$107.68**	**$107.68**
10.	**Market Value of Portfolio**													
11	**Market Value of Brown Portfolio**													
12	Non-Renewable Energy	Line 4 - Line 6	GWh	2,837	*32,170*	*30,895*	*30,941*	*31,058*	*31,058*	*31,058*	*31,077*	*31,077*	*31,077*	*31,077*
13	Actual 2018 Brown Power Benchmark1	Exhibit 3, Line 5	$/MWh	$33.77	*$45.13*	*$45.07*	*$45.14*	*$45.07*	*$45.07*	*$45.07*	*$45.07*	*$45.07*	*$45.05*	*$45.05*
14	**Market Value of Brown Portfolio**	Line 12 x Line 13	$000	**$95,801**	***$1,451,805***	***$1,392,555***	***$1,396,778***	***$1,399,877***	***$1,399,877***	***$1,399,877***	***$1,400,572***	***$1,400,553***	***$1,399,929***	***$1,399,929***
15	**Market Value of Green Portfolio**													
16	Renewable Energy	Line 6	GWh	278	10,759	14,931	16,188	17,729	18,081	18,100	18,415	18,635	18,650	18,650
17	Updated Weighted Average 2018 Green Benchmark1	Exhibit 3, Line 10	$/MWh	$57.93	$61.57	$61.55	$61.57	$61.55	$61.55	$61.55	$61.55	$61.55	$61.54	$61.54
18	**Market Value of Green Portfolio**	Line 16 * Line 17	$000	**$16,132**	**$662,407**	**$919,013**	**$996,712**	**$1,091,230**	**$1,112,850**	**$1,114,025**	**$1,133,373**	**$1,146,913**	**$1,147,767**	**$1,147,767**
19	**Capacity Adder**													
20	Average Monthly NQC	Line 8	MW	636	10,052	10,370	10,677	10,854	10,881	11,438	11,455	11,521	11,521	11,521
21	Capacity Value per Resolution E-4475	Exhibit 3, Line 11	$/kW-Year	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27
22	**Market Value of Capacity**	Line 20 x Line 21	$000	**$37,061**	**$585,722**	**$604,274**	**$622,143**	**$632,438**	**$634,033**	**$666,484**	**$667,483**	**$671,322**	**$671,348**	**$671,348**
23	**Portfolio Market Value**	Line 14 + Line 18+ Line 22	$000	**$148,994**	**$2,699,934**	**$2,915,841**	**$3,015,633**	**$3,123,545**	**$3,146,761**	**$3,180,385**	**$3,201,428**	**$3,218,789**	**$3,219,045**	**$3,219,045**
24	Line Loss Adjusted Portfolio Market value	Line 23 x Exhibit 3, Line 19	$000	$157,934	$2,861,930	$3,090,792	$3,196,571	$3,310,958	$3,335,567	$3,371,208	$3,393,514	$3,411,916	$3,412,187	$3,412,187
25	**Indifference Amount**													
26	Portfolio Total Cost	Line 2	$000	$250,757	$4,238,609	$4,706,946	$4,886,952	$5,055,360	$5,084,257	$5,098,836	$5,110,403	$5,132,525	$5,133,983	$5,133,983
27	Portfolio Market Value	Line 24	$000	$157,934	$2,861,930	$3,090,792	$3,196,571	$3,310,958	$3,335,567	$3,371,208	$3,393,514	$3,411,916	$3,412,187	$3,412,187
28	**Total Indifference Amount (Unadjusted)**	Line 26 - Line 27	$000	**$92,823**	**$1,376,679**	**$1,616,155**	**$1,690,381**	**$1,744,402**	**$1,748,691**	**$1,727,627**	**$1,716,889**	**$1,720,609**	**$1,721,795**	**$1,721,795**
29	**DWR Revenue Requirement**		$000											
30	**One-Time Adjustments (if applicable)**		$000											
31	**Carry Over Negative Indifference (if applicable)**		$000											
32	**Adjusted Indifference Amounts**	Sum (Lines 28:32)	$000	**$92,823**	**$1,376,679**	**$1,616,155**	**$1,690,381**	**$1,744,402**	**$1,748,691**	**$1,727,627**	**$1,716,889**	**$1,720,609**	**$1,721,795**	**$1,721,795**
33	2018 Trued-Up Indifference Amount (w/FF&U)	Line 32 * FF&U @ 1.011389	$000	$93,881	$1,392,358	$1,634,561	$1,709,633	$1,764,269	$1,768,607	$1,747,303	$1,736,443	$1,740,205	$1,741,405	$1,741,405
34	**2018 Forecast Indifference Amount (w/FF&U)**	Exhibit 1, Line 33		**$93,881**	**$1,748,124**	**$1,988,254**	**$2,063,293**	**$2,121,410**	**$2,127,109**	**$2,105,880**	**$2,095,598**	**$2,100,188**	**$2,100,652**	**$2,100,652**
35	**2018 Cumulative Indifference True-Up Adjustment**	Line 33 - Line 34	$000	**$0**	**-$355,766**	**-$353,693**	**-$353,661**	**-$357,140**	**-$358,503**	**-$358,577**	**-$359,155**	**-$359,983**	**-$359,247**	**-$359,247**
36	**2018 Incremental Indifference True-Up Adjustment**	Line 35 (vintage - previous vintage)	$000		**-$355,766**	**$2,073**	**$32**	**-$3,479**	**-$1,363**	**-$74**	**-$578**	**-$829**	**$736**	**$0**

Notes

[1] Input changes from 2018 PCIA Standard Template (D.18-01-009) are shown in green font.
[2] CTC adjustments are shown in red font.
[3] Lines added to 2018 PCIA Standard Template use to calculated the 2018 Incremental Indifference True-up Adjustment are shown in blue font.

Joint CCAs' Protest to PG&E AL 5527-E
Attachment A Page 2

Appendix B, Exhibit 3
Pacific Gas and Electric Company
Calculation of Updated Renewable Benchmark by Vintage (2009 - 2018)[1]

Indifference Calculation Inputs and Sources 2018 ERRA Forecast				Updated Renewable Benchmark ($/MWh) PCIA Vintages											
Line No.	Description	Source of Data	Value	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	**Source of Data**	**Use of Data**
1	On Peak NP 15 Price ($/MWh)	Platt's on October[2]	[redacted]												
2	Off Peak NP 15 Price ($/MWh)	Platt's on October[2]	[redacted]												
3	On Peak Load Weight (%)	2016 Recorded Load - On Peak Hours	61.1%												
4	Off Peak Load Weight (%)	2016 Recorded Load - Off Peak Hours	38.9%												
5	Base Load Weighted Average Price ($/MWh)	Line 1 x Line 3 + Line 2 x Line 4	$33.77	**$45.13**	**$45.07**	**$45.14**	**$45.07**	**$45.07**	**$45.07**	**$45.07**	**$45.07**	**$45.05**	**$45.05**	Exhibit 2 Line 2	Exhibit 4, Line 13
6	IOU Green Benchmark ($/MWh)	Energy Division Data (See Below)	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47		
7	IOU RPS Premium ($/MWh)	Line 6 - Line 5	$27.70	$16.34	$16.40	$16.33	$16.40	$16.40	$16.40	$16.40	$16.40	$16.42	$16.42		
8	DOE Renewable Adder ($/MWh)	Department of Energy Website -- Advice 5151-E	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64		
9	Weighted Average Renewable Premium ($/MWh)	68% x Line 7 + 32% x Line 8	$24.16	$16.44	$16.48	$16.43	$16.48	$16.48	$16.48	$16.48	$16.48	$16.49	$16.49		
10	Weighted Average Renewable Benchmark ($/MWh)	Line 9 + Line 5	$57.93	**$61.57**	**$61.55**	**$61.57**	**$61.55**	**$61.55**	**$61.55**	**$61.55**	**$61.55**	**$61.54**	**$61.54**		Exhibit 4, Line17
11	Capacity Benchmark ($/kW-Year)	2015 CEC Report -- Advice 5151-E	$58.27												
12	6% Line Loss Adjustment Factor	Resolution E-4475	1.060												
IOU Green Benchmark -- As Calculated by Energy Division															
13	Total IOU Renewable Resource Cost ($000)	2018 ERRA Forecast	$417,124												
14	Total IOU Renewable Resource Capacity (MW)	2018 ERRA Forecast	493												
15	Total IOU Renewable Resource Capacity Value ($000)	Line 14 x $58.27	$28,741												
16	Revised IOU Renewable Resource Cost	Line 13 - Line 15	$388,383												
17	Total IOU Renewable Energy (MWh)	2018 ERRA Forecast	6,318,256												
18	IOU Green Benchmark	Line 16 x 1000 / Line 17	$61.47												
19	1.06 x Load @ Customer Retail Meter=Load @ Generator (due to losses)														

Brown Power Benchmark from Exhibit 2

Note
[1] PG&E used the 2018 PCIA Standard Template input form modified to input the actual brown power benchmarks and calculate the updated renewable benchmarks by vintage.
[2] Confidential Platts forward prices are available in the original 2018 PCIA Standard Template.

Proposed 2019 ERRA Forecast PCIA Rates Including 2018 Actual Brown Power True-up (with DWR Franchise Fee)

	Proposed PCIA Rates by Vintage										
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	0.01869	0.02206	0.02306	0.02398	0.02413	0.02414	0.02414	0.02397	0.02403	0.02411	0.02982
Small L&P	0.01967	0.02296	0.02395	0.02486	0.02500	0.02501	0.02502	0.02486	0.02492	0.02499	0.02920
Medium L&P	0.02070	0.02415	0.02517	0.02612	0.02628	0.02630	0.02630	0.02612	0.02619	0.02627	0.03054
E19	0.01936	0.02253	0.02347	0.02435	0.02450	0.02451	0.02451	0.02435	0.02441	0.02448	0.02807
Streetlights	0.01861	0.02130	0.02210	0.02288	0.02300	0.02301	0.02302	0.02289	0.02293	0.02300	0.02400
Standby	0.01578	0.01823	0.01896	0.01965	0.01976	0.01977	0.01978	0.01965	0.01970	0.01976	0.02180
Agriculture	0.01695	0.01986	0.02074	0.02154	0.02167	0.02168	0.02168	0.02153	0.02159	0.02166	0.02586
E20 T (Excluding FPP)	0.01656	0.01924	0.02004	0.02079	0.02091	0.02093	0.02092	0.02080	0.02084	0.02090	0.02386
E20 P (Excluding FPP)	0.01763	0.02050	0.02136	0.02216	0.02229	0.02230	0.02231	0.02216	0.02221	0.02228	0.02551
E20 S (Excluding FPP)	0.01843	0.02145	0.02234	0.02318	0.02332	0.02333	0.02333	0.02319	0.02323	0.02330	0.02676
System Average PCIA Rate by Vintage	0.01964	0.02334	0.02578	0.02549	0.02771	0.02801	0.02789	0.02757	0.02709	0.02871	0.02891

	Adjusted 2019 Forecast of Vintage Sales										
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Residential	58,817,639	16,249,497	364,477,237	767,825	160,684,492	1,184,674,713	4,753,883	2,858,695,925	969,700,325	7,460,250,301	
Small L&P	16,892,326	28,128,872	149,763,301	2,909,222	291,377,806	197,876,661	112,379,786	1,115,623,245	41,765,086	2,442,739,134	
Medium L&P	50,772,049	190,091,623	131,300,355	25,960,921	254,787,798	168,496,378	90,102,673	1,298,475,911	40,057,665	2,994,893,946	
E19	341,197,671	813,604,406	160,760,827	44,982,607	257,422,191	184,176,709	89,772,815	1,113,474,795	579,017,197	3,601,731,775	
Streetlights	2,450,065	219,654	2,352,651	-	7,436,939	8,346,427	223,974	22,159,216	13,261,110	67,140,990	
Standby	-	-	8,049	-	149,973	72,215	36,168	3,239,389	8,079,256	19,494,840	
Agriculture	71,789	1,972,356	6,494,976	451,780	869,063	62,866,240	1,604,829	59,054,272	46,489,726	749,789,118	
E20 T (Excluding FPP)	231,280,379	679,998,332	121,739,794	43,163,632	-	24,129,981	-	327,617,822	1,859,510	543,654,063	
E20 P (Excluding FPP)	260,280,385	344,890,103	182,203,163	25,513,977	120,494,235	59,927,830	15,360,376	340,209,911	93,625,635	1,400,539,917	
E20 S (Excluding FPP)	75,916,436	138,130,318	29,499,760	9,520,239	21,122,118	21,955,394	-	147,826,180	52,803,275	501,484,641	
Total	**1,037,678,739**	**2,213,285,160**	**1,148,600,113**	**153,270,204**	**1,114,344,615**	**1,912,522,546**	**314,234,505**	**7,286,376,664**	**1,846,658,784**	**19,781,718,725**	**36,808,690,055**

	PCIA Revenue										
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Residential	$ 1,099,451	$ 358,431	$ 8,406,013	$ 18,415	$ 3,877,342	$ 28,596,777	$ 114,757	$ 68,515,330	$ 23,300,721	$ 179,854,451	$ 314,141,687
Small L&P	$ 332,346	$ 645,881	$ 3,586,335	$ 72,326	$ 7,285,631	$ 4,949,518	$ 2,811,329	$ 27,731,487	$ 1,040,609	$ 61,032,801	$ 109,488,262
Medium L&P	$ 1,050,934	$ 4,589,893	$ 3,304,919	$ 678,205	$ 6,695,055	$ 4,430,781	$ 2,369,617	$ 33,916,341	$ 1,049,052	$ 78,670,278	$ 136,755,077
E19	$ 6,606,449	$ 18,327,825	$ 3,773,387	$ 1,095,437	$ 6,306,326	$ 4,513,655	$ 2,200,454	$ 27,117,416	$ 14,134,368	$ 88,172,546	$ 172,247,862
Streetlights	$ 45,585	$ 4,678	$ 52,001	$ -	$ 171,087	$ 192,091	$ 5,157	$ 507,256	$ 304,121	$ 1,544,439	$ 2,826,415
Standby	$ -	$ -	$ 153	$ -	$ 2,964	$ 1,428	$ 715	$ 63,663	$ 159,136	$ 385,150	$ 613,208
Agriculture	$ 1,217	$ 39,176	$ 134,696	$ 9,733	$ 18,830	$ 1,362,673	$ 34,791	$ 1,271,437	$ 1,003,635	$ 16,238,903	$ 20,115,091
E20 T (Excluding FPP)	$ 3,828,972	$ 13,082,209	$ 2,440,227	$ 897,452	$ -	$ 505,022	$ -	$ 6,813,883	$ 38,760	$ 11,364,442	$ 38,970,967
E20 P (Excluding FPP)	$ 4,588,866	$ 7,071,637	$ 3,891,826	$ 565,497	$ 2,685,969	$ 1,336,424	$ 342,618	$ 7,538,583	$ 2,079,890	$ 31,210,464	$ 61,311,775
E20 S (Excluding FPP)	$ 1,399,368	$ 2,962,505	$ 659,106	$ 220,724	$ 492,585	$ 512,220	$ -	$ 3,427,674	$ 1,226,835	$ 11,686,446	$ 22,587,463
Total	**$ 18,953,189**	**$ 47,082,235**	**$ 26,248,664**	**$ 3,557,788**	**$ 27,535,788**	**$ 46,400,589**	**$ 7,879,438**	**$ 176,903,070**	**$ 44,337,127**	**$ 480,159,919**	**$ 879,057,807**

Joint CCA Proposed Rates with Brown Power True Up - Forecasted Generation

Filled out by Electric Rates

Filing Name: **2019 ERRA Advice Letter XXXX-E** | 5/8/19

ELECTRIC RATES

Average Rate (cents/kWh) (1)

	Bundled					Direct/Community Choice Access				
	5/1/19 Present (A)	5/1/19 Forecast Adj (B)	7/1/19 Proposed (C)	Rate Change (C) - (B)	% Change	5/1/19 Present (D)	5/1/19 Forecast Adj (E)	7/1/19 Proposed (F)	Rate Change (F) - (E)	% Change
Customer Class										
Residential	21.62	21.41	22.15	0.73	3.4%	15.97	16.67	15.99	-0.68	-4.1%
CARE	14.40	14.27	14.92	0.65	4.6%	5.39	6.76	5.99	-0.78	-11.5%
Non-CARE	24.44	24.34	25.11	0.77	3.2%	17.73	18.11	17.45	-0.66	-3.7%
Small Commercial	24.75	24.87	25.57	0.70	2.8%	16.17	16.14	15.99	-0.15	-0.9%
Medium Commercial	21.88	22.07	22.83	0.76	3.5%	12.50	12.71	12.80	0.09	0.7%
Large Commercial (E-19)	19.17	19.47	20.26	0.78	4.0%	9.35	10.08	10.33	0.25	2.5%
E-19 T	13.57	13.29	13.80	0.51	3.9%	6.70	7.95	8.37	0.42	5.3%
E-19 P	17.16	17.41	18.30	0.89	5.1%	9.12	9.61	9.94	0.34	3.5%
E-19 S	19.39	19.72	20.49	0.77	3.9%	9.37	10.11	10.36	0.25	2.5%
Streetlight	24.07	25.67	26.27	0.60	2.3%	16.19	15.15	16.81	1.66	10.9%
Standby	17.71	16.83	16.20	-0.63	-3.7%	25.54	14.97	15.46	0.49	3.3%
Agriculture	21.11	21.06	21.72	0.66	3.2%	12.62	16.27	15.06	-1.21	-7.4%
Industrial (E-20)	15.39	15.60	16.20	0.61	3.9%	6.53	6.63	6.78	0.14	2.1%
E-20 T	12.78	12.86	13.39	0.53	4.1%	3.78	4.15	4.24	0.09	2.2%
E-20 P	16.46	16.66	17.29	0.64	3.8%	7.79	7.99	8.16	0.17	2.1%
E-20 S	18.27	18.81	19.49	0.69	3.6%	8.43	8.51	8.69	0.18	2.1%
Average System Rate	20.60	20.53	21.23	0.70	3.4%	11.70	12.44	12.29	-0.15	-1.2%

RESIDENTIAL TIERS

	Non-CARE (cents/kWh) 5/1/19	Non-CARE (cents/kWh) 07/01/19	% Change	CARE (cents/kWh) 5/1/19	CARE (cents/kWh) 7/1/19	% Change
Tier 1	22.28	22.55	1.2%	14.27	14.45	1.2%
Tier 2	28.04	28.38	1.2%	17.94	18.15	1.2%
Tier 3	28.04	28.38	1.2%	17.94	18.15	1.2%
Tier 4	28.04	28.38	1.2%	17.94	18.15	1.2%
Tier 5	49.13	49.73	1.2%	31.42	31.81	1.2%

ELECTRIC BILLS

	Average Monthly Non-CARE Bill ($) Bundled				Average Monthly CARE Bill ($) Bundled			
	5/1/19	7/1/19	Bill Change	% Change	5/1/19	7/1/19	Bill Change	% Change
Customer								
Residential								
350 kWh	$75.48	$76.45	$0.98	1.3%	$46.67	$47.30	$0.63	1.3%
500 kWh	$117.54	$119.03	$1.49	1.3%	$73.58	$74.53	$0.95	1.3%
700 kWh	$173.62	$175.79	$2.17	1.3%	$109.45	$110.84	$1.39	1.3%
Small Commercial	$275.89	$283.66	$7.77	2.8%	N/A	N/A	N/A	N/A

PACIFIC GAS AND ELECTRIC COMPANY
Advice Letter Related Documents 5527-E
Data Response

PG&E Data Request No.:	Joint-CCA_001-Q07		
PG&E File Name:	AdviceLetterRelatedDocuments5527-E_DR_Joint-CCA_001-Q07		
Request Date:	April 18, 2019	Requester DR No.:	001
Date Sent:	May 1, 2019	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Monterey Bay Community Power/ Peninsula Clean Energy/ Pioneer Community Energy/ Silicon Valley Clean Energy/ Sonoma Clean Power
PG&E Witness:		Requester:	Tim Lindl

QUESTION 7

Please reference page 9 of PG&E's Opening Comments on the Decision ("PG&E's Comments") and the Decision at Section 3.3.7, Section 8, Finding of Fact 6, Conclusion of Law 5, Ordering Paragraph 2, and Ordering Paragraph 5, on pp. 20-22, 26-28, 30, 32 and 33-34. Please describe whether the methodology referenced in those pages of the Decision reflect one of the four approaches described in Lines 1-4 in the table on p. 9 of PG&E's Comments. If so, please indicate which approach. If not, please indicate the approach in PG&E's Comments most similar to the Decision's adopted methodology and describe and explain the difference between the two.

ANSWER 7

PG&E objects to this question on the grounds of relevancy.

The approaches described in Lines 1-4 in the table on p.9 of PG&E's Comments do <u>not</u> reflect the methodology described in the referenced pages of the Decision. This is because PG&E's opening comments preceded the issuance of the Decision, with the amounts shown based on preliminary estimates of actual values and with a calculation that included the CCA's Parties' estimate of departed load for comparative purposes.

That said, the cumulative estimated true-up of Lines 2 and 3 most closely aligns with the Decision's order to calculate the true-up by replacing the forecasted 2018 brown power benchmark in the 2018 Forecast ERRA case by applying actual 2018 market prices to actual PCIA-eligible generation deliveries and realized Ancillary Services revenues in accordance with D.18-10-019.[1] The ERRA Decision directs the IOUs to the PCIA Decision (D.18-10-019) for additional guidance (pages 141 and 161).[2] Page 141 of D.18-10-019 includes a discussion of why the PCIA Decision adopts the limited true-up proposed by AReM/DACC. The AReM/DACC proposal is described in D.18-10-019 as

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[1] D.19-02-023, page 21.

[2] D.19-02-023, p. 21, footnotes 30 and 32.

the difference between the forecast and actual market prices, sales volumes and PCIA revenue collections.[3] Page 161 of D.18-10-019 describes the components of a brown power true-up that need to be included in the PABA accounting framework, including subaccounts to account for generation resource costs and net California Independent System Operator market revenues associated with energy and ancillary services.[4] Furthermore, the Decision, which was revised after PG&E's opening comments and just before the Commission's approval, ordered PG&E to update the REC benchmark based on the average actual net CAISO revenues for PCIA-eligible resources.

Within the limitations of not having yet established the PABA framework, PG&E's actual brown power true-up complies with the direction provided in D.19-02-023, including the references to D.18-10-019. This includes a true-up between forecasted and actual market prices, sales volumes and generation resource costs.

PG&E was unable to include a true-up for PCIA revenue collections (or billed revenues) as part of the Advice Letter because a system for tracking that information did not exist for 2018. While D.18-10-019 orders the inclusion of PCIA revenue collections in the brown power true-up as well as the development and implementation of systems by the IOUs to track these revenues for future true-ups, D.18-10-019 was not approved until October 2018. PG&E is currently developing a system for tracking all the necessary information. It will be implemented once PG&E's PABA Advice Letter decision is final. In the absence of such a system for 2018 and lacking any approved Commission methodology for calculating or estimating a PCIA revenue collections true-up for 2018, PG&E was not able to implement this component of the brown power true-up.

[3] D.18-10-019, p. 138

[4] D.18-10-019, p. 161, Ordering Paragraph 7.

PACIFIC GAS AND ELECTRIC COMPANY
Advice Letter Related Documents 5527-E
Data Response

PG&E Data Request No.:	Joint-CCA_002-Q01		
PG&E File Name:	AdviceLetterRelatedDocuments5557_DR_Joint-CCA_002-Q01		
Request Date:	April 19, 2019	Requester DR No.:	002
Date Sent:	May 3, 2019	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Monterey Bay Community Power/ Peninsula Clean Energy/ Pioneer Community Energy/ Silicon Valley Clean Energy/ Sonoma Clean Power
Responder:	Rob Bremault/ Sharon Pierson	Requester:	Tim Lindl

QUESTION 01

Please reference p. 8 of the Advice Letter, wherein PG&E states “For the 2018 vintage load, the overpayment amount in 2018 is determined by multiplying the refund rate times the actual sales for this vintage. The resulting PCIA overpayment is used to derive the applicable refund rate. … [T]he 2018 vintage brown power true-up is allocated pro rata based on the amount of customer sales contributing to the 2018 overcollection. This methodology ensures that all customers equitably benefit from and are indifferent to the brown power true-up. Applying the full adjustment to all 2018 vintage customers would lead to an inequitable outcome as certain 2018 vintage sales were not subject to a 2018 PCIA rate for the entire year.”

a) Please explain whether basing the 2018 vintage brown power true-up on actual sales for that vintage, and thereby allocating it “pro rata based on the amount of customer sales contributing to the 2018 over-collection,” results in a higher PCIA rate for departed customers within the 2018 vintage than “[a]pplying the full adjustment to all 2018 vintage customers.” If it does result in a higher PCIA, please provide the amount of that difference in $/kWh.

b) Please explain whether basing the 2018 vintage brown power true-up on actual sales for that vintage, and thereby allocating it “pro rata based on the amount of customer sales contributing to the 2018 over-collection,” results in a lower rate for bundled customers. If so, please explain whether the amount of that decrease equals the amount of the increase departed customers in the 2018 vintage will experience in sub-part (a). If not, why not?

c) Please explain whether PG&E is proposing a different PCIA rate for different CCA customers within the 2018 vintage or whether each departed customer within the 2018 vintage will pay the same PCIA rate.

d) Please reference sub-question (c). If each departed customer within the 2018 vintage will pay the same PCIA rate, does PG&E agree that the true-up refund will be smaller for some departed customers, and larger for others, than it otherwise would be if it was solely based on the amount of actual kWh each of those customers purchased that were subject to a 2018 PCIA rate for the entire year?

e) Please describe whether PG&E is aware of an instance in which a PCIA rate for a specific vintage was determined "*pro rata* based on the amount of customer sales" within that vintage year.

f) Does PG&E agree that many CCA and other departing load customers have left PG&E's service territory on dates other than the first or last day of a year?

ANSWER 01

PG&E responds as follows:

a) The result is a higher PCIA rate compared to applying the full adjustment to all 2018 vintage customers. The difference would be the difference between the 2017 vintage rates by class and the 2018 vintage rates by class as shown on Confidential Appendix C, page 6 of 7. There is about a 3 - 5 percent difference in the non-residential rate, excluding streetlights.

An excerpt with an analysis of the difference is shown below:

	2019 Proposed PCIA Rates by Vintage ($/kWh)		Incremental Difference ($/kWh)	Percent Differential ($/kWh)
Rate Group	**2017**	**2018**		
Residential	0.02802	0.02960	0.00158	5.34%
Small L&P	0.02788	0.02912	0.00124	4.26%
Medium L&P	0.02920	0.03052	0.00132	4.33%
E19	0.02695	0.02800	0.00105	3.77%
Streetlights	0.02370	0.02401	0.00032	1.32%
Standby	0.02116	0.02187	0.00071	3.26%
Agriculture	0.02454	0.02593	0.00140	5.38%
E20 T (Excluding FPP)	0.02294	0.02392	0.00098	4.11%
E20 P (Excluding FPP)	0.02449	0.02555	0.00106	4.15%
E20 S (Excluding FPP)	0.02568	0.02680	0.00113	4.21%
System Average PCIA Rate by Vintage	0.02709	0.02871	0.00162	5.66%

b) Yes. Because the 2019 ERRA forecast is the transitional year prior to implementation of the PCIA OIR decision, the 2019 ERRA revenue requirement is determined on a residual basis (total ERRA RRQ less PCIA revenues). The ERRA revenue requirements that underlie bundled customers' rates will move in the opposite direction – dollar for dollar – with the derived 2019 PCIA revenue requirement.

PG&E notes that upon implementation of the PABA, the ERRA portion of the generation revenue requirement will no longer be calculated on a residual basis because the PCIA revenue requirement will be determined directly and will reflect both departing customers' and bundled customers' above-market-cost obligation. That is, the PCIA revenue requirement will be set equal to the total portfolio indifference amount. Currently the PCIA revenue requirement is imputed, based on calculated rates and multiplied by non-exempt departing load sales.

c) The 2018 vintage PCIA rate is differentiated by customer class. Please see Appendix C, page 6 of 7.

d) Not applicable. The rates will be differentiated by class.

e) This is the first instance, but PG&E would also note this is the first instance where there has been a partial true-up of costs and market revenues for the vintaged PCIA rates.

The unique circumstances requiring a partial true-up of the costs and market revenues which results in an additional cost shift to bundled customers, warranted the pro-rata calculation that was implemented for the 2018 Vintage customers.

f) Yes.

PACIFIC GAS AND ELECTRIC COMPANY
Advice Letter Related Documents 5527-E
Data Response

PG&E Data Request No.:	Joint-CCA_002-Q02		
PG&E File Name:	AdviceLetterRelatedDocuments5527_DR_Joint-CCA_002-Q02		
Request Date:	April 19, 2019	Requester DR No.:	002
Date Sent:	May 3, 2019	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Monterey Bay Community Power/ Peninsula Clean Energy/ Pioneer Community Energy/ Silicon Valley Clean Energy/ Sonoma Clean Power
Responder	George Clavier/Amol Patel	Requester:	Tim Lindl

QUESTION 02

Please reference the Advice Letter, Appendix B, Exhibits 1 to 4. Please provide the hourly generation (MWh) by individual resources scheduled by PG&E in 2018. As part of your answer, please explain whether the amount of generation corresponds with PG&E's reported generation in its 2018 ERRA Compliance application Chapter 1.

ANSWER 02

Hourly generation (MWh) by individual resources were not used as part of the 2018 true-up analysis. The CAISO generation data PG&E used in calculating the brown power true-up were obtained from the CAISO settlement system using a database script that aggregated CAISO generation by resource, month and CAISO market (Day Ahead or Real-Time). This data were summarized by resource and CAISO market in PG&E's response to AdviceLetterRelatedDocuments5527_DR_Joint-CCA_001-Q02. The monthly detail is provided in tab "01. Monthly CAISO DA_RT_Energy" (see filename, "AdviceLetterRelatedDocuments5527-E_DR_Joint CCA_002_Q02Atch01.xlsx").

The amount of generation provided as part of Appendix B, Exhibits 1 to 4 reflects all Day Ahead and Real Time market awards as well as final resource meter quantities which are settled against those market awards. The generation amounts provided in Chapter 1 of the 2018 Compliance application are reflective of these market awards and thus would be a subset of the data provided in Appendix B, Exhibits 1 to 4.

PACIFIC GAS AND ELECTRIC COMPANY
Advice Letter Related Documents 5527-E
Data Response

PG&E Data Request No.:	Joint-CCA_002-Q06		
PG&E File Name:	AdviceLetterRelatedDocuments5527_DR_Joint-CCA_002-Q06		
Request Date:	April 19, 2019	Requester DR No.:	002
Date Sent:	May 3, 2019	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Monterey Bay Community Power/ Peninsula Clean Energy/ Pioneer Community Energy/ Silicon Valley Clean Energy/ Sonoma Clean Power
Responder	George Clavier	Requester:	Tim Lindl

QUESTION 06

Please reference the following:

- Pages 6-7 of the Advice Letter, wherein PG&E states "The brown power benchmarks applicable to each vintage were calculated by aggregating resource-specific CAISO revenues/charges (net revenue) by vintage and then dividing those values by each vintage's recorded generation,"
- Footnote 13 of the Advice Letter, which states "The CAISO revenues/charges used in the derivation of the indices include day-ahead and real time energy revenues, ancillary service revenues, grid management charges (GMC), and various other resource-specific charge categories."
- D.19-02-023 at Section 3.3.7, footnote 31, on pp. 20-22 stating "Actual 2018 market prices of PCIA-eligible generation deliveries and realized ancillary services shall be determined by the net of CAISO revenues for PCIA eligible resources."
- Page 9 of PG&E's Comments on the Alternate Proposed Decision in A.18-06-001, wherein PG&E uses the term "net CAISO revenues".

With regard to these passages:

a) Please provide a definition of "net CAISO revenues."

b) Please explain the extent to which PG&E agrees that the "net of CAISO revenues" is calculated by netting the "day-ahead and real time energy revenues" and "ancillary service revenues" with the "grid management charges (GMC), and various other resource-specific charge categories."

c) Please provide examples of "other resource-specific charge categories".

ANSWER 06

a) For the purposes of the 2018 brown power true-up, net CAISO revenues correspond to the sum of revenues and charges associated with the 43 CAISO charge codes listed in: *AdviceLetterRelatedDocuments5527-E_DR_Joint-CCA_001-Q02Atch01.xlsx, Sheet 02. CAISO Charge Codes*

b) PG&E agrees with the characterization of “net of CAISO revenues” as described in Question 6 part b (above), but notes that footnote 31 does not reflect the full extent of the true-up mandated by D.19-02-023. D.19-02-023 at Section 3.3.7, p. 21 states that the true should be performed “in accordance with D.18-10-01”, referencing p. 161 of that decision. D.18-10-019 at p. 161 describes the components of a brown power true-up that need to be included in the PABA accounting framework, including subaccounts to account for generation resource costs and net California Independent System Operator market revenues associated with energy and ancillary services. *See also* D.18-10-019 at OP 7.

c) For a complete list of other charge categories used in the brown power true-up, please refer to: *AdviceLetterRelatedDocuments5527-E_DR_Joint-CCA_001-Q02Atch01.xlsx, Sheet 02. CAISO Charge Codes*

Line No.	Category Name	Charge Code #	Charge Code Name
1	Ancillary Services	3303	Supplement Reactive Energy Settlement
2	Ancillary Services	6100	Day Ahead Spinning Reserve Capacity Settlement
3	Ancillary Services	6124	No Pay Spinning Reserve Settlement
4	Ancillary Services	6170	Real Time Spinning Reserve Capacity Settlement
5	Ancillary Services	6200	Day Ahead Non-Spinning Reserve Capacity Settlement
6	Ancillary Services	6224	No Pay Non-Spinning Reserve Settlement
7	Ancillary Services	6270	Real Time Non-Spinning Reserve Capacity Settlement
8	Ancillary Services	6500	Day Ahead Regulation Up Capacity Settlement
9	Ancillary Services	6524	Non Compliance Regulation Up Settlement
10	Ancillary Services	6570	Real Time Regulation Up Capacity Settlement
11	Ancillary Services	6600	Day Ahead Regulation Down Capacity Settlement
12	Ancillary Services	6624	Non Compliance Regulation Down Settlement
13	Ancillary Services	6670	Real Time Regulation Down Capacity Settlement
14	Ancillary Services	7251	Regulation Up Mileage Settlement
15	Ancillary Services	7261	Regulation Down Mileage Settlement
16	Cost Recovery	6620	Bid Cost Recovery Settlement
17	Cost Recovery	6630	IFM Bid Cost Recovery Settlement
18	DA Energy	6011	Day Ahead Energy, Congestion, Loss Settlement
19	DA Energy	6301	Day Ahead Inter-SC Trades Settlement
20	FLEX RAMP	7070	Flexible Ramp Forecast Movement Settlement
21	FLEX RAMP	7071	Daily Flexible Ramp Up Uncertainty Capacity Settlement
22	FLEX RAMP	7077	Daily Flexible Ramp Up Uncertainty Award Allocation
23	FLEX RAMP	7078	Monthly Flexible Ramp Up Uncertainty Award Allocation
24	FLEX RAMP	7081	Daily Flexible Ramp Down Uncertainty Capacity Settlement
25	FLEX RAMP	7087	Daily Flexible Ramp Down Uncertainty Award Allocation
26	FLEX RAMP	7088	Monthly Flexible Ramp Down Uncertainty Award Allocation
27	GMC	4515	GMC - Bid Segment Fee
28	GMC	4560	GMC - Market Services Charge
29	GMC	4561	GMC - System Operations Charge
30	Miscellaneous	701	Forecasting Service Fee
31	Miscellaneous	6455	Declined Hourly Pre-Dispatch Penalty Settlement
32	Miscellaneous	6976	Transmission Loss Obligation Charge for Real Time Schedules Under Control Agreements
33	Miscellaneous	7891	Monthly Capacity Procurement Mechanism Settlement
34	RAAIM	8830	Monthly Resource Adequacy Availability Incentive Mechanism Settlement
35	RAAIM	8831	Monthly Resource Adequacy Availability Incentive Mechanism Allocation
36	RT SPOT	6371	FMM Inter SC Trades Settlement
37	RT SPOT	6460	FMM Instructed Imbalance Energy Settlement
38	RT SPOT	6470	Real Time Instructed Imbalance Energy Settlement
39	RT SPOT	6475	Real Time Uninstructed Imbalance Energy Settlement
40	RT SPOT	6482	Real Time Excess Cost for Instructed Energy Settlement
41	RT SPOT	6488	Exceptional Dispatch Uplift Settlement
42	RUC	6800	Day Ahead Residual Unit Commitment (RUC) Availability Settlement
43	RUC	6824	No Pay Residual Unit Commitment (RUC) Settlement

PACIFIC GAS AND ELECTRIC COMPANY
Advice Letter Related Documents 5527-E
Data Response

PG&E Data Request No.:	Joint-CCA_003-Q13		
PG&E File Name:	AdviceLetterRelatedDocuments5557_DR_Joint-CCA_003-Q13		
Request Date:	April 22, 2019	Requester DR No.:	003
Date Sent:	May 6, 2019	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Monterey Bay Community Power/ Peninsula Clean Energy/ Pioneer Community Energy/ Silicon Valley Clean Energy/ Sonoma Clean Power
Responder:	Sharon Pierson	Requester:	Richard McCann

QUESTION 13

Please reference PG&E Advice Letter 5527-E, p.8. PG&E states, “For the 2018 vintage load, the overpayment amount in 2018 is determined by multiplying the refund rate times the actual sales for this vintage.” Please cite to the portion of the ERRA Forecast decision that authorizes vintaging of customers sales specifically for the 2018 vintage, or any single year.

ANSWER 13

The ERRA Forecast decision does not explicitly address “. . . vintaging of customer sales for the 2018 vintage or any single year.”

The decision requires a brown power true-up to actuals for PCIA for forecast year 2018. PG&E took an approach to fairly implement the requirement for all customers.

Customer vintages 2009 through 2017 paid the PCIA for the entire year and fairly received credit for the brown power true-up for the entire year.

In contrast, 2018 vintage customers are defined as customers that departed on or after July 1 of 2018 and therefore only paid the PCIA during the last 6 months of the year. Depending on the date of their departure, they may have only paid the PCIA for as little as one month. As such, to implement a fair and equitable refund for the 2018 vintage customers, an overpayment amount (or true-up revenue requirement) for the 2018 vintage was calculated by multiplying the true-up rate times the sales that paid the PCIA rate. That calculation directly ties the overpayment to be refunded to the volume of the PCIA amounts these customers overpaid.

Using actual PCIA sales from the 2018 vintage eliminates any over- or understatement of the overpayment amount and appropriately refunds a fair and equitable amount to the 2018 vintage customers.

KEYES & FOX LLP

May 20, 2019

CPUC Energy Division
Attn: Tariff Unit and Edward Randolph, Director
505 Van Ness Avenue
San Francisco, CA 94102
EDTariffUnit@cpuc.ca.gov

Re: Joint CCAs' Protest of Pacific Gas and Electric Company ("PG&E") Supplemental Advice Letter 5527-E-A

Dear Tariff Unit and Mr. Randolph:

By way of this letter, submitted pursuant to General Order 96-B, East Bay Community Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Silicon Valley Clean Energy, and Sonoma Clean Power, (collectively, the Joint Community Choice Aggregators ("Joint CCAs")) jointly protest Pacific Gas & Electric Company ("PG&E")'s Supplemental Advice Letter 5527-E-A ("Supplemental Advice Letter").[1] On May 7, 2019, Energy Division requested PG&E file the Supplemental Advice Letter to align PG&E's approach with that in Appendix C to Southern California Edison's ("SCE's") Advice Letters 3972-E and 3972-E-A ("SCE Advice Letters").[2]

The Supplemental Advice Letter fails to achieve the required alignment with the SCE Advice Letters, D.19-02-023 ("ERRA Forecast Decision") and Commission rules and precedent. First, the Supplemental Advice Letter commits a mathematical error when applying line loss factors. Second, PG&E excludes the competition transition charge ("CTC") components of the Power Charge Indifference Amount ("PCIA") calculation, which both Appendices B and C of the SCE Advice Letters included and which the Commission did not authorize PG&E to exclude. Third, the Supplemental Advice Letter continues to pro-rate the 2018 vintage; PG&E applies an unauthorized, unjust and unreasonable methodology that does not follow the ERRA Forecast

1 General Order ("GO") No. 96-B §7.4.2.

2 PG&E Supplemental Advice Letter No. 5527-E-A, p. 2 (May 15, 2019) ("Supplemental Advice Letter"); Southern California Edison Advice Letter 3972-E (March 19, 2019) ("SCE Advice Letter"); Southern California Edison Advice Letter 3972-E-A (April 25, 2019).

Decision, has never been approved,[3] and should be rejected in favor of applying the complete refund to the 2018 vintage. Finally, PG&E continues to argue that Energy Division's requested approach to exclude actual generation costs from the incremental indifference calculation does not comport with the ERRA Forecast Decision or D.18-10-019 (the "PCIA Decision"), which is false.

The Joint CCAs, therefore, protest the Supplemental Advice Letter on the grounds it: [4]

- Commits material errors by miscalculating line losses;
- Excludes the CTC components of the indifference calculation when determining the brown power true-up ("BPTU") refund rate—an unauthorized approach that fails to follow both SCE's approach and Commission directives to calculate the BPTU utilizing the PCIA workpapers filed to date in A.18-06-001; and
- Continues to result in unauthorized, unjust and unreasonable rates by including the *pro rata* adjustment to the 2018 vintage, an issue that was not applicable to SCE's 2018 vintage.[5]

The Joint CCAs believe their protest ("Original Protest") to the original Advice Letter 5527-E ("Original AL") demonstrates the value of a BPTU targeting only non-Renewable Portfolio Standard ("RPS") eligible resources,[6] and that granting the Original Protest will ensure D.19-02-023 is implemented to the letter.

In the alternative, granting this Protest to the Supplemental Advice Letter to utilize forecasted generation costs, address the line loss miscalculation, and fix PG&E's treatment of the

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3 PG&E Response to Joint-CCA_002-Q01(e) (See Attachment B to the Original Protest).

4 GO 96-B §§ 5.1, 7.4.2(2), (3), and (6). PG&E also inappropriately requests the adoption of new policy in a Tier 2 advice letter process intended to address "ministerial" actions for which hearings are not required.

5 Unlike departed customers in PG&E's service territory, it does not appear as though 2018 vintage customers in SCE's service territory paid the PCIA at any point in 2018. *See* SCE Advice Letter at 7-8, n. 14. For example, Clean Power Alliance's customers are 2017 vintage (municipal customers that left in February 2018 and June 2018) and 2018 vintage (residential customers and non-residential customers that left in February 2019 or are leaving in May 2019). However, because the 2018 vintage customers left in 2019, they did not pay the PCIA at all in 2018. The 2017 vintage customers paid the PCIA for only part of 2018, but they were trued up via SCE applying the true-up to 2017 vintage customers.

6 Joint CCAs Protest to PG&E Advice Letter 5527-E (May 8, 2019) ("Original Protest").

2018 vintage results in a revised BPTU value of $83.6 million[7] instead of the $55.1 million value stated in the Supplemental Advice Letter.[8] The Joint CCAs have attached workpapers to this Protest to enact these changes using data from the Supplemental Advice Letter and workpapers.[9]

Reinserting the CTC components of the indifference calculation to align with the Commission-approved methodology implemented by SCE likely would also increase the value of the BPTU. The Joint CCAs are unable to determine the amount of such an increase at this time because PG&E has not provided the actual market prices or production quantities for its CTC resources. We respectfully request this Protest be granted and PG&E be required to submit a second supplemental advice letter including the CTC within the true-up methodology.

Finally, time is of the essence if finalized 2019 rates for bundled and unbundled ratepayers are to be effective on July 1, 2019. PG&E included a shortened time period for protests to its Supplemental Advice Letter of three business days. Recognizing the urgent need for 2019 rates to be put in place, and congruent with the shortened protest period allocated to the Joint CCAs, we respectfully request Energy Division require PG&E to reply to this protest within two business days, *i.e.*, by May 22, 2019.[10]

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[7] In this Protest, the Joint CCAs provide values for two changes to the methodology in the Supplemental Advice Letter 5227-E-A. The value of each individual change depends on the sequence in which it is implemented as an adjustment to the PCIA and BPTU calculation. However, the cumulative effect of all adjustments would be the same regardless of sequence. The workpapers attached hereto demonstrate this phenomenon. The identified corrections are quantified in order of 1) fixing the *pro rata* adjustment to 2018 vintage rates, and 2) resolving the math error committed when computing line losses. If a subset of the identified corrections is adopted, the individual impact may vary, and PG&E should be required to submit a supplemental BPTU calculation incorporating the approved changes.

The same sequencing issue occurs in the Original Protest. Contrary to PG&E's assertions in their Reply to the Original Protest, the Joint CCAs did not get the math wrong. *See* PG&E Reply to Joint CCAs Protest of Advice Letter 5527-E, p. 4 (May 15, 2019) ("PG&E Reply"). The $111.8 million figure in the Joint CCA's Protest captures the impact of reverting to forecasted 2018 portfolio costs *plus* utilizing an actual market price for brown power resources only (excluding RPS resources from the market price calculation) and applying the updated Green Power Benchmark to forecasted generation quantities for RPS resources. The effects of all of these factors magnify the true-up's value when compared with the Supplemental Advice Letter's limited approach.

[8] Supplemental Advice Letter at 3.

[9] *See* Attachment A to this Protest.

[10] *See* GO 96-B § 1.3.

I. The Supplemental Advice Letter Commits a Mathematical Error and Does Not Follow the Approach in SCE's Appendix C.

Energy Division requested a supplement to the Original AL 5527-E that would align with the approach utilized in Appendix C to the SCE Advice Letters.[11] Achieving this alignment requires PG&E to revise the Supplemental Advice Letter in two ways. First, PG&E's line loss calculations should be corrected. To address line losses, SCE simply calculated the impact of the true-up "at the generator:"

> Both the actual "Market Value of Energy" and the actual "renewable energy" that is multiplied by the RPS Adder reflect energy that is measured at the generator. In other words, unlike the forecast generation, which is "at the customer meter" and thus needs to be multiplied by a line loss factor, the actual generation does not reflect any line losses. The "Line Loss Adjusted Portfolio Market Value" line in Appendix B8 has been modified accordingly to ensure that there is no double counting of line losses. This is consistent with the proposed operation of [Portfolio Allocation Balancing Account], which will record actual net CAISO revenues (with no additional line loss adjustment) and imputed [Renewable Energy Credit] revenues based on energy that is measured at the generator (with no additional line loss adjustment).[12]

PG&E conceptually attempts to do the same thing but commits a mathematical error when doing so.[13] To calculate the BPTU, PG&E measures actual output "at the generator" but then scales it down by a 0.94 multiplier to represent output at the meter. The scaled-down generation is applied to the updated market benchmarks to calculate the actual market value, which is then grossed back up for losses using a 1.06 multiplier.

However, with a line loss factor of six percent, it is mathematically incorrect to scale down generation by a factor of 0.94 and then scale it back up again by a factor of 1.06. To illustrate, if actual generation was 1,000 GWh, scaling it down by 0.94 results in 940 GWh at the meter. Grossing that back up by 1.06 results in output at the generator of 996 GWh, which understates the quantity used to calculate the portfolio market value by 4 GWh. The proper

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11 Supplemental Advice Letter at 2.

12 SCE Advice Letter at 6, n. 9.

13 If portfolio cost and value measurements are both done at the generator, as SCE's approach contemplates, there is no need to scale them down to the customer meter only to scale them back up to the generator.

calculation would be to scale generation down by *dividing* initial volumes by 1.06. For example, 1,000 GWh would scale down to 943 (1,000 / 1.06) at the meter, which would then be grossed back up to 1,000 GWh (943 * 1.06).

To avoid this error, and comport with SCE's approach, PG&E should be required to correct its calculation of line loss factors. Doing so will increase the value of the BPTU by $4.4 million.[14]

Second, following SCE's approach means the CTC components should be reinserted into the template and calculation. SCE includes the CTC "vintage" in its BPTU, explaining: "Because all departing load customers . . . pay the same CTC (*i.e.*, the CTC is not vintage-differentiated), the overcollection related to the CTC-eligible resources is returned to . . . departing load customers through the 2018 True-Up Surcharge/Refund reflected in their vintaged PCIA."[15] If the CTC is excluded from the total portfolio calculation methodology for calculating the incremental indifference amount, customers will forfeit the true-up from these resources.

This is what happens in the Supplemental Advice Letter. PG&E modified the PCIA template in the Original AL to exclude CTC resources from the BPTU calculation,[16] but it did not remedy that exclusion in the Supplemental Advice Letter in response to Energy Division's request. PG&E's original justification for removing the CTC is "the true up applies to PCIA-eligible generation," for which it cites to Ordering Paragraph 5.[17] However, PG&E's Ordering Paragraph 5 is nearly identical to SCE's Ordering Paragraph 7.[18] Neither mentions excluding the Ongoing CTC, meaning the adoption of PG&E's methodology would conflict with a prior application of the same language for SCE.

Not only does it conflict with SCE's approach, PG&E's modification of the PCIA

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14 *See* Attachment A to this Protest.

15 SCE Advice Letter, p. 4-5, 7, n. 13.

16 PG&E Advice Letter 5527-E, p. 6 (April 18, 2019) ("Original AL").

17 *Id.*

18 *Compare* D.19-02-023 at Ordering Paragraph 5 *to* D.19-02-024 at Ordering Paragraph 7.

template to calculate the BPTU conflicts with Commission directives. The Commission directed the incremental indifference amount must "be reflected in rates in a manner compliant with the PCIA workpapers filed in this proceeding,"[19] *i.e.*, in a manner that includes CTC-vintage resources. PG&E's treatment of the CTC also creates an inconsistency between the implementation of the ERRA Forecast Decision's ratemaking changes, which PG&E has applied to the CTC,[20] and the ERRA Forecast Decision's BPTU implementation, from which PG&E has excluded the CTC.

To be consistent with its disposition of SCE's advice letters, and to follow the Commission's clear intent to modify as little of the indifference calculation as possible when implementing the BPTU, PG&E's unauthorized revision to the indifference calculation should be rejected. Including CTC resources in the true-up calculation likely would increase the refund due to unbundled customers because of the higher market price of brown power being applied to the CTC resources' output. PG&E should be required to file a second supplement calculating the BPTU with CTC resources included.[21]

II. PG&E's Supplemental Advice Letter Continues its Unjust, Unreasonable and Unauthorized Treatment of the 2018 Vintage.

The Supplemental Advice Letter continues to pro-rate the refund rate for the 2018 vintage. Rather than apply the cumulative 2018 true-up rate to the 2018 vintage sales forecast as it did for all other vintages, PG&E multiplies the cumulative 2018 true-up rate by the ratio of actual 2018 vintage sales to forecasted 2018 vintage sales, effectively eliminating $24.1 million of the BPTU refund.[22] The Joint CCAs protested this approach on both substantive and procedural grounds in the Original Protest and protests the continued use of that approach here.[23]

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19 D.19-02-023 at 21-22.

20 Original AL at 3, n. 7 (stating "The rate design adopted for the PCIA will also apply to the Ongoing CTC rate as well given the total portfolio calculation methodology for calculating the indifference amount.").

21 As noted *supra*, the Joint CCAs are unable to determine the amount of the resulting increase in the value of the BPTU because PG&E has provided neither the actual market prices nor the actual production quantities from CTC resources.

22 *See* Attachment A to this Protest. Due to sequencing, the value of this correction to PG&E's filing is greater than that reported in the Joint CCAs' Original Protest. In the Original Protest, the impact of eliminating the *pro rata* adjustment to the 2018 vintage was calculated first, resulting in a $15.7

The Commission has never approved or even considered PG&E's approach previously, meaning its adoption is inappropriate for a Tier 2 Advice Letter process.[24] Applying a pro-rated 2018 vintage true-up rate to all customers also conflicts with two directives in D.19-02-023:

1. The "difference between the total indifference amount in the 2018 Forecast ERRA case and that calculated with the 2018 brown power true-up," must "be reflected in rates in a manner compliant with the PCIA workpapers filed in this proceeding."[25]

2. "The calculation of the PCIA rate shall follow as it has in past ERRA proceedings by allocating the cumulative vintaged Indifference Amount to each rate group using the allocation factors *followed by dividing by the forecasted system sales for the forecast year*."[26]

PG&E's approach does not comply with either directive because it revises the forecasted system sales figures approved in D.19-02-023, and used in the PCIA workpapers filed to date in this proceeding, for the purpose of calculating the BPTU. PG&E's Reply to the Original Protest does not rebut any of these points, and the utility's approach to the 2018 vintage should be rejected on these procedural grounds.

PG&E's Reply suggests that "[u]sing actual PCIA sales from the 2018 vintage eliminates any over- or under-statement of the overpayment amount and appropriately refunds a fair and equitable amount to the 2018 vintage customers."[27] However, this argument continues to ignore—and PG&E's Reply fails to rebut—the fact that PG&E's approach would effectively deny a refund to customers that should receive one.[28] Customers paying for above-market costs throughout the entire year via the ERRA (and then later the PCIA) should benefit from a true-up of market values for the time they paid the ERRA during the year.[29] They do not benefit under

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million increase in the BPTU refund. Here, the 2018 *pro rata* adjustment is eliminated after PG&E updated its filing to rely on forecasted portfolio costs. The increased BPTU refund resulting from PG&E's update magnifies the impact of the *pro rata* adjustment to 2018 vintage BPTU rates.

23 Original Protest at 11-15.

24 *See id.* at 13-15.

25 D.19-02-023 at 21-22; *see* Original Protest at 13-14.

26 D.19-02-023 at Ordering Paragraph 4 (emphasis added); *see also id.* at Finding of Fact 9 (stating "It is reasonable to continue to calculate the PCIA rate by dividing the allocated vintaged Indifference Amount by the forecasted system sales.").

27 PG&E Reply at 8.

28 *See* Original Protest at 11-13.

29 *See id*.

PG&E's approach because actual energy and ancillary services revenues earned by PCIA-eligible resources in 2018 are directly recorded to the ERRA balancing account and reflected in the final year-end ERRA balance.[30] The reconciliation of any over or under-collection based on market values within those year-end balances takes place via the ERRA, a mechanism that does not apply to customers once they depart.

Further, PG&E's proposed policy chooses to take the refunds for certain departed customers (those departing earlier in the year) and distribute them to other departed customers (those departing later in the year) without any authorization from the Commission.[31] That is, not only is PG&E's new approach unauthorized by the Commission and inappropriate for a Tier 2 Advice Letter, it is also questionable policy.

The approach should be rejected and the cumulative 2018 true-up rate should be applied to the 2018 vintage on a 1-to-1 basis. Based on the Joint CCAs' calculations, removing the *pro rata* adjustment to 2018 rates to correctly implement D.19-02-023 increases the amount of the BPTU by $24.1 million.[32]

III. Excluding Actual Generation Costs Comports with Both the ERRA Forecast Decision and the PCIA Decision.

Despite the Supplemental Advice Letter's claims to the contrary,[33] Energy Division's request to exclude actual generation costs from the true-up complies with both D.19-02-023 and D.18-10-019. PG&E states, "[t]he ERRA Forecast Decision specifically directs PG&E to pages 141 and 161 of the PCIA Decision."[34] The ERRA Forecast Decision cites to page 141 of D.18-10-019 for the sole purpose of supporting its conclusion "that, for now, the true-up shall be limited to brown power."[35] It does not cite to page 141 for any methodological approach regarding the components of the BPTU.

30 *See, e.g.,* SCE Advice Letter at 7, n. 13.
31 *See* Original Protest at 11-13.
32 *See* Attachment A to this Protest.
33 Supplemental Advice Letter at 3.
34 *Id.* at 2.
35 D.19-02-023 at 21, n. 30.

The ERRA Forecast Decision addresses the methodological question of what components should be included in the BPTU "in accordance with D.18-10-019" by citing to page 161,[36] which is where Ordering Paragraphs ("OPs") 6 and 7 are contained in D.18-10-019. As the Joint CCAs have stated *ad nauseum* in A.18-06-001 and this advice letter process, OPs 6 and 7 establish a bifurcated true-up process.[37] OP 6 in D.18-10-019—being implemented here—requires the IOUs to "annually true-up their PCIA rates to reflect actual values realized in market transactions for the subject year *for the Brown Power Index*,"[38] *i.e.*, the market value of brown power. OP 7 sets the stage for the *future* evolution of the true-ups conveying the Commission's intent to true-up generation costs and RA and RPS-eligible resources at a later date. Indeed, nearly all of page 141—on which PG&E's arguments rely entirely—discusses how the Commission agrees with AReM/DACC that it does "not have sufficient record evidence to explain in detail how RPS or RA should be trued up."[39]

D.19-02-023 clearly implements an interim approach for 2018 to calculate the BPTU "applying actual 2018 market prices" and "Ancillary Services revenues" for brown power.[40] The Commission expressly rejected an approach that includes more.[41] PG&E reargues this point in its reply to the Original Protest, effectively suggesting that D.19-02-023 allows the utility to include any true-up components mentioned OP 7 in D.18-10-019 as long as those components can be calculated today.[42] As noted in our Original Protest, Energy Division rejected this same argument from SCE,[43] concluding that under a strict reading of its ERRA decision "SCE was ordered to update the market value of its energy portfolio for 2018, but was neither permitted nor instructed to update *any* of its generation costs."[44]

Like SCE, PG&E must apply the Commission's interim approach in strict accordance

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36 *Id.* at 21, n. 32.
37 Original AL at 5, n. 10 (citing to "D.18-10-019, OP 7 at 161").
38 D.18-10-019 at Ordering Paragraph 6 (emphasis added).
39 *Id.* at 141.
40 D.19-02-023 at Ordering Paragraph 5.
41 *See* Original Protest at 3-9.
42 PG&E Reply at 3.
43 Energy Division, *Non-Standard Disposition Letter re Southern California Edison Advice Letters 3972-E and 3972-E-A -- 2019 Energy Resource Recovery Account Forecast Proceeding Revenue Requirement in Accordance with D.19-02-024*, pp. 1, 4 (April 20, 2019).
44 *Id.* at 4 (emphasis in original).

with the methodology the ERRA Forecast Decision prescribes. That methodology only authorizes a true-up of forecasted market prices with actual market prices, and PG&E's argument in the Supplemental Advice Letter regarding the inclusion of actual generation costs should be rejected.[45] To the extent PG&E believes the true-up should have included more components, its remedy lies in an Application for Rehearing or Petition for Modification of the ERRA Forecast Decision and not in a Tier 2 Advice Letter.

IV. Conclusion

For the reasons stated above, if the Commission does not grant the Original Protest, we respectfully request the Commission grant this Protest to the Supplemental Advice Letter and require PG&E to file a second supplemental advice letter implementing the BPTU with corrected line loss factors, CTC resources included, and without any *pro rata* adjustment to the 2018 vintage.

Respectfully submitted,

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45 *See* GO 96-B §7.4.2(2), (3).

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Service List for A.18-06-001

	PCIA	BPTU	BPTU Difference
PG&E Original Advice Letter	1,006,565,926	(36,326,825)	
PG&E Revised AL - No Portfolio Cost True Up	987,817,039	(55,075,712)	(18,748,887)
Remove 2018 Pro Rata Adjustment	963,722,748	(79,170,002)	(24,094,290)
Correct Line Losses	959,338,476	(83,554,275)	(4,384,272)

Advice 5527-E-A

Appendix B, Exhibit 4

Pacific Gas and Electric Company

2018 Alternative True-up Indifference Adjustment Calculation

Line No.	Description	Source/Equation	Unit	CTC	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Cost of Portfolio													
1	Total Portfolio Cost[4]	Exhibit 1, Line 1	$000	$250,757	$4,489,366	$4,957,703	$5,137,709	$5,306,117	$5,335,014	$5,349,593	$5,361,160	$5,383,282	$5,384,740	$5,384,740
2	Total Portfolio Cost Less Ongoing-CTC[2]	Line 1 Less CTC (250,757)	$000		$4,238,609	$4,706,946	$4,886,952	$5,055,360	$5,084,257	$5,098,836	$5,110,403	$5,132,525	$5,133,983	$5,133,983
3	Supply At Customer Meter[1]	Worksheet 1, Line 6	GWh	3,116	45,718	48,916	50,302	51,851	52,185	52,198	52,520	52,701	52,707	52,707
4	Supply At Customer Meter Less Ongoing-CTC[2]	Line 3 Less CTC (3,116)	GWh		42,603	45,801	47,187	48,735	49,070	49,082	49,405	49,586	49,592	49,592
5	Renewable Supply at Customer Meter less Ongoing-CTC[1]	Worksheet 4, Line 493	GWh	278	10,585	15,062	16,402	17,833	18,168	18,181	18,484	18,665	18,671	18,671
6	Renewable Supply at Customer Meter less Ongoing-CTC[2]	Line 5 Less CTC (278)	GWh		10,306	14,783	16,124	17,555	17,889	17,902	18,206	18,386	18,393	18,393
7	Average Monthly Net Qualifying Capacity	Worksheet 1, Line 9	MW	636	10,688	11,006	11,313	11,490	11,517	12,074	12,091	12,157	12,157	12,157
8	Average Monthly Net Qualifying Capacity less-CTC[2]	Line 7 Less CTC (636)	MW		10,052	10,370	10,677	10,854	10,881	11,438	11,455	11,521	11,521	11,521
9	**Portfolio Unit Cost**	Line 1 / Line 3	$/MWh	**$80.48**	**$98.20**	**$101.35**	**$102.14**	**$102.33**	**$102.23**	**$102.49**	**$102.08**	**$102.15**	**$102.16**	**$102.16**
10	**Market Value of Portfolio**													
11	**Market Value of Brown Portfolio**													
12	Non-Renewable Energy	Line 4 - Line 6	GWh	2,837	32,296	31,017	31,063	31,180	31,180	31,180	31,199	31,199	31,199	31,199
13	Actual 2018 Brown Power Benchmark[1]	Exhibit 3, Line 5	$/MWh	$33.77	$42.03	$41.35	$41.30	$41.00	$40.94	$40.93	$40.83	$40.80	$40.80	$40.80
14	**Market Value of Brown Portfolio**	Line 12 x Line 13	$000	**$95,801**	**$1,357,363**	**$1,282,619**	**$1,282,943**	**$1,278,429**	**$1,276,373**	**$1,276,319**	**$1,274,008**	**$1,272,930**	**$1,272,851**	**$1,272,851**
15	**Market Value of Green Portfolio**													
16	Renewable Energy	Line 6	GWh	278	10,306	14,783	16,124	17,555	17,889	17,902	18,206	18,386	18,393	18,393
17	Updated Weighted Average 2018 Green Benchmark[1]	Exhibit 3, Line 10	$/MWh	$57.93	$60.57	$60.36	$60.34	$60.25	$60.23	$60.22	$60.19	$60.18	$60.18	$60.18
18	**Market Value of Green Portfolio**	Line 16 * Line 17	$000	**$16,132**	**$624,306**	**$892,303**	**$972,945**	**$1,057,614**	**$1,077,395**	**$1,078,148**	**$1,095,848**	**$1,106,526**	**$1,106,879**	**$1,106,879**
19	**Capacity Adder**													
20	Average Monthly NQC	Line 8	MW	636	10,052	10,370	10,677	10,854	10,881	11,438	11,455	11,521	11,521	11,521
21	Capacity Value per Resolution E-4475	Exhibit 3, Line 11	$/kW-Year	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27	$58.27
22	**Market Value of Capacity**	Line 20 x Line 21	$000	**$37,061**	**$585,722**	**$604,274**	**$622,143**	**$632,438**	**$634,033**	**$666,484**	**$667,483**	**$671,322**	**$671,348**	**$671,348**
23	**Portfolio Market Value**	Line 14 + Line 18+ Line 22	$000	**$148,994**	**$2,567,391**	**$2,779,195**	**$2,878,032**	**$2,968,480**	**$2,987,801**	**$3,020,951**	**$3,037,339**	**$3,050,779**	**$3,051,078**	**$3,051,078**
24	Line Loss Adjusted Portfolio Market value	Line 23 x Exhibit 3, Line 12	$000	$157,934	$2,721,434	$2,945,947	$3,050,714	$3,146,589	$3,167,069	$3,202,208	$3,219,580	$3,233,825	$3,234,143	$3,234,143
25	**Indifference Amount**													
26	Portfolio Total Cost	Line 2	$000	$250,757	$4,238,609	$4,706,946	$4,886,952	$5,055,360	$5,084,257	$5,098,836	$5,110,403	$5,132,525	$5,133,983	$5,133,983
27	Portfolio Market Value	Line 24	$000	$157,934	$2,721,434	$2,945,947	$3,050,714	$3,146,589	$3,167,069	$3,202,208	$3,219,580	$3,233,825	$3,234,143	$3,234,143
28	**Total Indifference Amount (Unadjusted)**	Line 26 - Line 27	$000	**$92,823**	**$1,517,175**	**$1,760,999**	**$1,836,238**	**$1,908,771**	**$1,917,188**	**$1,896,627**	**$1,890,824**	**$1,898,700**	**$1,899,840**	**$1,899,840**
29	**DWR Revenue Requirement**		$000											
30	**One-Time Adjustments (if applicable)**		$000											
31	**Carry Over Negative Indifference (if applicable)**		$000											
32	**Adjusted Indifference Amounts**	Sum (Lines 28:32)	$000	**$92,823**	**$1,517,175**	**$1,760,999**	**$1,836,238**	**$1,908,771**	**$1,917,188**	**$1,896,627**	**$1,890,824**	**$1,898,700**	**$1,899,840**	**$1,899,840**
33	2018 Trued-Up Indifference Amount (w/FF&U)	Line 32 * FF&U @ 1.011389	$000	$93,881	$1,534,454	$1,781,055	$1,857,151	$1,930,510	$1,939,023	$1,918,228	$1,912,358	$1,920,324	$1,921,477	$1,921,477
34	**2018 Forecast Indifference Amount (w/FF&U)[3]**	Exhibit 1, Line 33		**$93,881**	**$1,748,124**	**$1,988,254**	**$2,063,293**	**$2,121,410**	**$2,127,109**	**$2,105,880**	**$2,095,598**	**$2,100,188**	**$2,100,652**	**$2,100,652**
35	**2018 Cumulative Indifference True-Up Adjustment[3]**	Line 33 - Line 34	$000	**$0**	**-$213,670**	**-$207,199**	**-$206,142**	**-$190,900**	**-$188,086**	**-$187,652**	**-$183,240**	**-$179,864**	**-$179,175**	**-$179,175**
36	**2018 Incremental Indifference True-Up Adjustment[3]**	Line 35 (vintage - previous vintage)	$000		**-$213,670**	**$6,471**	**$1,057**	**$15,242**	**$2,813**	**$434**	**$4,412**	**$3,375**	**$689**	**$0**

Notes
[1] Input changes from 2018 PCIA Standard Template (D.18-01-009) are shown in green font.
[2] CTC adjustments are shown in red font.
[3] Lines added to 2018 PCIA Standard Template use to calculated the 2018 Incremental Indifference True-up Adjustment are shown in blue font.
[4] Line Changed from AL 5527-E (reflects forecast from Nov. 2018 update).

Pacific Gas and Electric Company

Calculation of Updated Renewable Benchmark by Vintage (2009 - 2018)[1]

Indifference Calculation Inputs and Sources 2018 ERRA Forecast				**Updated Renewable Benchmark ($/MWh) PCIA Vintages**											
Line No.	Description	Source of Data	Value	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	**Source of Data**	**Use of Data**
1	On Peak NP 15 Price ($/MWh)	Platt's on October[2]	[redacted]												
2	Off Peak NP 15 Price ($/MWh)	Platt's on October[2]	[redacted]												
3	On Peak Load Weight (%)	2016 Recorded Load - On Peak Hours	61.1%				Brown Power Benchmark from Exhibit 2								
4	Off Peak Load Weight (%)	2016 Recorded Load - Off Peak Hours	38.9%												
5	Base Load Weighted Average Price ($/MWh)	Line 1 x Line 3 + Line 2 x Line 4	$33.77	**$42.03**	**$41.35**	**$41.30**	**$41.00**	**$40.94**	**$40.93**	**$40.83**	**$40.80**	**$40.80**	**$40.80**	Exhibit 2 Line 2	Exhibit 4, Line 13
6	IOU Green Benchmark ($/MWh)	Energy Division Data (See Below)	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47	$61.47		
7	IOU RPS Premium ($/MWh)	Line 6 - Line 5	$27.70	$19.44	$20.12	$20.17	$20.47	$20.53	$20.54	$20.64	$20.67	$20.67	$20.67		
8	DOE Renewable Adder ($/MWh)	Department of Energy Website -- Advice 5151-E	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64	$16.64		
9	Weighted Average Renewable Premium ($/MWh)	68% x Line 7 + 32% x Line 8	$24.16	$18.55	$19.01	$19.04	$19.24	$19.29	$19.29	$19.36	$19.38	$19.38	$19.38		
10	Weighted Average Renewable Benchmark ($/MWh)	Line 9 + Line 5	$57.93	**$60.57**	**$60.36**	**$60.34**	**$60.25**	**$60.23**	**$60.22**	**$60.19**	**$60.18**	**$60.18**	**$60.18**		Exhibit 4, Line17
11	Capacity Benchmark ($/kW-Year)	2015 CEC Report -- Advice 5151-E	$58.27												
12	6% Line Loss Adjustment Factor	Resolution E-4475	1.060												
IOU Green Benchmark -- As Calculated by Energy Division															
13	Total IOU Renewable Resource Cost ($000)	2018 ERRA Forecast	$417,124												
14	Total IOU Renewable Resource Capacity (MW)	2018 ERRA Forecast	493												
15	Total IOU Renewable Resource Capacity Value ($000)	Line 14 x $58.27	$28,741												
16	Revised IOU Renewable Resource Cost	Line 13 - Line 15	$388,383												
17	Total IOU Renewable Energy (MWh)	2018 ERRA Forecast	6,318,256												
18	IOU Green Benchmark	Line 16 x 1000 / Line 17	$61.47												
19	1.06 x Load @ Customer Retail Meter=Load @ Generator (due to losses)														

Notes

[1] PG&E used the 2018 PCIA Standard Template input form modified to input the actual brown power benchmarks and calculate the updated renewable benchmarks by vintage.
[2] Confidential Platts forward prices are available in the original 2018 PCIA Standard Template.

Rate Group	Actual 2018 Sales									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Residential	57,362,420	16,111,227	356,558,054	7,000,279	148,255,857	1,099,377,224	5,038,068	2,773,859,958	2,620,184,341	846,400,353
Small L&P	19,117,080	35,104,636	142,201,979	5,382,565	278,995,037	190,928,225	108,675,983	1,097,291,706	1,263,361,737	202,490,240
Medium L&P	46,155,854	179,057,630	127,849,177	25,172,090	243,612,006	163,858,665	84,006,515	1,227,873,737	1,211,512,124	173,412,052
E19	322,222,838	791,762,250	167,308,955	47,310,618	244,421,461	180,757,568	87,248,116	1,114,711,202	1,964,848,769	325,758,248
Streetlights	2,152,492	301,488	2,680,477	1,798	6,949,987	8,479,120	93,416	23,597,884	59,478,201	9,617,443
Standby	-	-	17,452	-	295,171	48,653	50,456	5,226,551	20,675,178	158
Agriculture	56,605	1,951,343	7,036,694	536,881	1,325,776	68,678,279	2,834,723	61,339,069	687,954,969	6,757,558
E20 T (Excluding FPP)	450,499,902	1,014,318,222	111,539,166	44,977,968	-	21,863,204	-	335,798,179	333,431,661	8,347,600
E20 P (Excluding FPP)	267,303,403	346,466,697	180,111,007	26,279,119	111,431,189	63,883,666	10,070,821	298,054,471	685,856,424	34,550,134
E20 S (Excluding FPP)	83,795,810	132,686,641	27,546,362	8,624,682	20,278,210	21,613,844	-	160,974,679	241,330,795	13,282,998
Total	1,248,666,403	2,517,760,132	1,122,849,324	165,286,000	1,055,564,694	1,819,488,448	298,018,098	7,098,727,435	9,088,634,200	1,620,616,784

	2019 forecast DA/CCA - PCIA Sales by Vintage										
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Residential	58,817,639	16,249,497	364,477,237	767,825	160,684,492	1,184,674,713	4,753,883	2,858,695,925	969,700,325	7,460,250,301	
Small L&P	16,892,326	28,128,872	149,763,301	2,909,222	291,377,806	197,876,661	112,379,786	1,115,623,245	41,765,086	2,442,739,134	
Medium L&P	50,772,049	190,091,623	131,300,355	25,960,921	254,787,798	168,496,378	90,102,673	1,298,475,911	40,057,665	2,994,893,946	
E19	341,197,671	813,604,406	160,760,827	44,982,607	257,422,191	184,176,709	89,772,815	1,113,474,795	579,017,197	3,601,731,775	
Streetlights	2,450,065	219,654	2,352,651	-	7,436,939	8,346,427	223,974	22,159,216	13,261,110	67,140,990	
Standby	-	-	8,049	-	149,973	72,215	36,168	3,239,389	8,079,256	19,494,840	
Agriculture	71,789	1,972,356	6,494,976	451,780	869,063	62,866,240	1,604,829	59,054,272	46,489,726	749,789,118	
E20 T (Excluding FPP)	231,280,379	679,998,332	121,739,794	43,163,632	-	24,129,981	-	327,617,822	1,859,510	543,654,063	
E20 P (Excluding FPP)	260,280,385	344,890,103	182,203,163	25,513,977	120,494,235	59,927,830	15,360,376	340,209,911	93,625,635	1,400,539,917	
E20 S (Excluding FPP)	75,916,436	138,130,318	29,499,760	9,520,239	21,122,118	21,955,394	-	147,826,180	52,803,275	501,484,641	
System Average PCIA Rate by Vintage	1,037,678,739	2,213,285,160	1,148,600,113	153,270,204	1,114,344,615	1,912,522,546	314,234,505	7,286,376,664	1,846,658,784	19,781,718,725	36,808,690,055

	UnAdjusted 2019 Forecast of Vintage Sales [1/]										
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Residential	58,817,639	16,249,497	364,477,237	767,825	160,684,492	1,184,674,713	4,753,883	2,858,695,925	969,700,325	7,460,250,301	
Small L&P	16,892,326	28,128,872	149,763,301	2,909,222	291,377,806	197,876,661	112,379,786	1,115,623,245	41,765,086	2,442,739,134	
Medium L&P	50,772,049	190,091,623	131,300,355	25,960,921	254,787,798	168,496,378	90,102,673	1,298,475,911	40,057,665	2,994,893,946	
E19	341,197,671	813,604,406	160,760,827	44,982,607	257,422,191	184,176,709	89,772,815	1,113,474,795	579,017,197	3,601,731,775	
Streetlights	2,450,065	219,654	2,352,651	-	7,436,939	8,346,427	223,974	22,159,216	13,261,110	67,140,990	
Standby	-	-	8,049	-	149,973	72,215	36,168	3,239,389	8,079,256	19,494,840	
Agriculture	71,789	1,972,356	6,494,976	451,780	869,063	62,866,240	1,604,829	59,054,272	46,489,726	749,789,118	
E20 T (Excluding FPP)	231,280,379	679,998,332	121,739,794	43,163,632	-	24,129,981	-	327,617,822	1,859,510	543,654,063	
E20 P (Excluding FPP)	260,280,385	344,890,103	182,203,163	25,513,977	120,494,235	59,927,830	15,360,376	340,209,911	93,625,635	1,400,539,917	
E20 S (Excluding FPP)	75,916,436	138,130,318	29,499,760	9,520,239	21,122,118	21,955,394	-	147,826,180	52,803,275	501,484,641	
Total	**1,037,678,739**	**2,213,285,160**	**1,148,600,113**	**153,270,204**	**1,114,344,615**	**1,912,522,546**	**314,234,505**	**7,286,376,664**	**1,846,658,784**	**19,781,718,725**	**36,808,690,055**

1/ The 2019 DA/CCA sales forecast was adjusted to reflect actual 2018 sales in the 2017 vintage. The adjustment results in lower sales in the 2018 vintage used to derive the refund rate for the 2018 vintage. The total 2019 DA/CCA sales forecast is unchanged.

2017	2018
2,620,184,341	4,729,094,833
1,263,361,737	1,548,466,144
1,211,512,124	1,898,480,200
1,964,848,769	2,283,158,129
59,478,201	42,561,053
20,675,178	12,357,889
687,954,969	475,295,560
333,431,661	344,625,383
685,856,424	887,810,170
241,330,795	317,893,948
9,088,634,200	**12,539,743,309**

Attachment A
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2018 Brown Power True Up Rate Calculation Using Top 100 Rate Design

2018 ERRA Forecast - Incremental Indifference Result - 2018 BrownPower True-up
pursuant to D.19-02-023

Rate Group	Total Billing Determinants (kWh)	Top 100 Hours Allocation	CTC RRQ N/A All	Incremental True-up Amount Allocated to Rate Group -- Total RRQ by Vintage x Column C 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Total RRQ			$ -	$ (213,669,842)	$ 6,470,855	$ 1,056,971	$ 15,242,388	$ 2,813,406	$ 434,396	$ 4,412,311	$ 3,375,068	$ 689,342	$ -
Residential	27,733,811,955	44.12%	$ -	$ (94,264,411)	$ 2,854,738	$ 466,302	$ 6,724,462	$ 1,241,186	$ 191,642	$ 1,946,573	$ 1,488,974	$ 304,116	$ -
Small L&P	7,971,460,610	9.34%	$ -	$ (19,964,717)	$ 604,619	$ 98,760	$ 1,424,206	$ 262,877	$ 40,589	$ 412,274	$ 315,357	$ 64,410	$ -
Medium L&P	10,113,075,637	12.02%	$ -	$ (25,690,483)	$ 778,020	$ 127,084	$ 1,832,661	$ 338,268	$ 52,229	$ 530,512	$ 405,800	$ 82,883	$ -
E19	12,840,853,289	12.84%	$ -	$ (27,430,518)	$ 830,716	$ 135,692	$ 1,956,788	$ 361,180	$ 55,767	$ 566,444	$ 433,285	$ 88,496	$ -
Streetlights	281,820,556	0.08%	$ -	$ (167,739)	$ 5,080	$ 830	$ 11,966	$ 2,209	$ 341	$ 3,464	$ 2,650	$ 541	$ -
Standby	320,417,307	0.18%	$ -	$ (388,533)	$ 11,766	$ 1,922	$ 27,716	$ 5,116	$ 790	$ 8,023	$ 6,137	$ 1,253	$ -
Agriculture	6,216,832,106	7.28%	$ -	$ (15,551,638)	$ 470,971	$ 76,930	$ 1,109,394	$ 204,770	$ 31,617	$ 321,143	$ 245,649	$ 50,173	$ -
E20 T (Excluding FPP)	5,543,883,711	4.57%	$ -	$ (9,761,969)	$ 295,635	$ 48,290	$ 696,381	$ 128,537	$ 19,846	$ 201,586	$ 154,197	$ 31,494	$ -
E20 P (Excluding FPP)	8,127,426,030	7.29%	$ -	$ (15,570,824)	$ 471,552	$ 77,025	$ 1,110,763	$ 205,022	$ 31,656	$ 321,540	$ 245,952	$ 50,235	$ -
E20 S (Excluding FPP)	2,373,994,137	2.28%	$ -	$ (4,879,011)	$ 147,758	$ 24,135	$ 348,050	$ 64,242	$ 9,919	$ 100,752	$ 77,067	$ 15,741	$ -
Total	81,523,575,337	100.00%											

Rate Group	Total Billing Determinants (kWh)	Top 100 Hours Allocation	CTC Rate N/A All	INCREMENTAL RATES 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Residential	27,733,811,955	44.12%	$ -	$ (0.00340)	$ 0.00010	$ 0.00002	$ 0.00024	$ 0.00004	$ 0.00001	$ 0.00007	$ 0.00005	$ 0.00001	$ -
Small L&P	7,971,460,610	9.34%	$ -	$ (0.00250)	$ 0.00008	$ 0.00001	$ 0.00018	$ 0.00003	$ 0.00001	$ 0.00005	$ 0.00004	$ 0.00001	$ -
Medium L&P	10,113,075,637	12.02%	$ -	$ (0.00254)	$ 0.00008	$ 0.00001	$ 0.00018	$ 0.00003	$ 0.00001	$ 0.00005	$ 0.00004	$ 0.00001	$ -
E19	12,840,853,289	12.84%	$ -	$ (0.00214)	$ 0.00006	$ 0.00001	$ 0.00015	$ 0.00003	$ 0.00000	$ 0.00004	$ 0.00003	$ 0.00001	$ -
Streetlights	281,820,556	0.08%	$ -	$ (0.00060)	$ 0.00002	$ 0.00000	$ 0.00004	$ 0.00001	$ 0.00000	$ 0.00001	$ 0.00001	$ 0.00000	$ -
Standby	320,417,307	0.18%	$ -	$ (0.00121)	$ 0.00004	$ 0.00001	$ 0.00009	$ 0.00002	$ 0.00000	$ 0.00003	$ 0.00002	$ 0.00000	$ -
Agriculture	6,216,832,106	7.28%	$ -	$ (0.00250)	$ 0.00008	$ 0.00001	$ 0.00018	$ 0.00003	$ 0.00001	$ 0.00005	$ 0.00004	$ 0.00001	$ -
E20 T (Excluding FPP)	5,543,883,711	4.57%	$ -	$ (0.00176)	$ 0.00005	$ 0.00001	$ 0.00013	$ 0.00002	$ 0.00000	$ 0.00004	$ 0.00003	$ 0.00001	$ -
E20 P (Excluding FPP)	8,127,426,030	7.29%	$ -	$ (0.00192)	$ 0.00006	$ 0.00001	$ 0.00014	$ 0.00003	$ 0.00000	$ 0.00004	$ 0.00003	$ 0.00001	$ -
E20 S (Excluding FPP)	2,373,994,137	2.28%	$ -	$ (0.00206)	$ 0.00006	$ 0.00001	$ 0.00015	$ 0.00003	$ 0.00000	$ 0.00004	$ 0.00003	$ 0.00001	$ -
Total	81,523,575,337	100.00%		$ (0.00262)	$ 0.00008	$ 0.00001	$ 0.00019	$ 0.00003	$ 0.00001	$ 0.00005	$ 0.00004	$ 0.00001	$ -

Rate Group	Total Billing Determinants (kWh)	Top 100 Hours Allocation	CTC Rate All	CUMULATIVE RATES 2009	2010	2011	2012	2013	2014	2015	2016	2017	
Residential	27,733,811,955	44.12%	$ -	$ (0.00340)	$ (0.00330)	$ (0.00328)	$ (0.00304)	$ (0.00299)	$ (0.00299)	$ (0.00291)	$ (0.00286)	$ (0.00285)	$ (0.00285)
Small L&P	7,971,460,610	9.34%	$ -	$ (0.00250)	$ (0.00243)	$ (0.00242)	$ (0.00224)	$ (0.00220)	$ (0.00220)	$ (0.00215)	$ (0.00211)	$ (0.00210)	$ (0.00210)
Medium L&P	10,113,075,637	12.02%	$ -	$ (0.00254)	$ (0.00246)	$ (0.00245)	$ (0.00227)	$ (0.00224)	$ (0.00223)	$ (0.00218)	$ (0.00214)	$ (0.00213)	$ (0.00213)
E19	12,840,853,289	12.84%	$ -	$ (0.00214)	$ (0.00207)	$ (0.00206)	$ (0.00191)	$ (0.00188)	$ (0.00188)	$ (0.00183)	$ (0.00180)	$ (0.00179)	$ (0.00179)
Streetlights	281,820,556	0.08%	$ -	$ (0.00060)	$ (0.00058)	$ (0.00057)	$ (0.00053)	$ (0.00052)	$ (0.00052)	$ (0.00051)	$ (0.00050)	$ (0.00050)	$ (0.00050)
Standby	320,417,307	0.18%	$ -	$ (0.00121)	$ (0.00118)	$ (0.00117)	$ (0.00108)	$ (0.00107)	$ (0.00106)	$ (0.00104)	$ (0.00102)	$ (0.00102)	$ (0.00102)
Agriculture	6,216,832,106	7.28%	$ -	$ (0.00250)	$ (0.00243)	$ (0.00241)	$ (0.00223)	$ (0.00220)	$ (0.00220)	$ (0.00215)	$ (0.00211)	$ (0.00210)	$ (0.00210)
E20 T (Excluding FPP)	5,543,883,711	4.57%	$ -	$ (0.00176)	$ (0.00171)	$ (0.00170)	$ (0.00157)	$ (0.00155)	$ (0.00155)	$ (0.00151)	$ (0.00148)	$ (0.00148)	$ (0.00148)
E20 P (Excluding FPP)	8,127,426,030	7.29%	$ -	$ (0.00192)	$ (0.00186)	$ (0.00185)	$ (0.00171)	$ (0.00169)	$ (0.00168)	$ (0.00164)	$ (0.00161)	$ (0.00161)	$ (0.00161)
E20 S (Excluding FPP)	2,373,994,137	2.28%	$ -	$ (0.00206)	$ (0.00199)	$ (0.00198)	$ (0.00184)	$ (0.00181)	$ (0.00180)	$ (0.00176)	$ (0.00173)	$ (0.00172)	$ (0.00172)
Total	81,523,575,337	100.00%		$ (0.00262)	$ (0.00254)	$ (0.00253)	$ (0.00234)	$ (0.00231)	$ (0.00230)	$ (0.00225)	$ (0.00221)	$ (0.00220)	$ (0.00220)

Actual 2018 Sales by Vintage

Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Residential	57,362,420	16,111,227	356,558,054	7,000,279	148,255,857	1,099,377,224	5,038,068	2,773,859,958	2,620,184,341	846,400,353
Small L&P	19,117,080	35,104,636	142,201,979	5,382,565	278,995,037	190,928,225	108,675,983	1,097,291,706	1,263,361,737	202,490,240
Medium L&P	46,155,854	179,057,630	127,849,177	25,172,090	243,612,006	163,858,665	84,006,515	1,227,873,737	1,211,512,124	173,412,052
E19	322,222,838	791,762,250	167,308,955	47,310,618	244,421,461	180,757,568	87,248,116	1,114,711,202	1,964,848,769	325,758,248
Streetlights	2,152,492	301,488	2,680,477	1,798	6,949,987	8,479,120	93,416	23,597,884	59,478,201	9,617,443
Standby	-	-	17,452	-	295,171	48,653	50,456	5,226,551	20,675,178	158
Agriculture	56,605	1,951,343	7,036,694	536,881	1,325,776	68,678,279	2,834,723	61,339,069	687,954,969	6,757,558
E20 T (Excluding FPP)	450,499,902	1,014,318,222	111,539,166	44,977,968	-	21,863,204	-	335,798,179	333,431,661	8,347,600
E20 P (Excluding FPP)	267,303,403	346,466,697	180,111,007	26,279,119	111,431,189	63,883,666	10,070,821	298,054,471	685,856,424	34,550,134
E20 S (Excluding FPP)	83,795,810	132,686,641	27,546,362	8,624,682	20,278,210	21,613,844	-	160,974,679	241,330,795	13,282,998
Total	1,248,666,403	2,517,760,132	1,122,849,324	165,286,000	1,055,564,694	1,819,488,448	298,018,098	7,098,727,435	9,088,634,200	1,620,616,784

Rate Group	2018 Vintage Revenues	2019 Forecast Sales of 2018 Vintage	2018 Vintage True-up Rate
Residential	$ (2,412,395)	7,460,250,301	$ (0.00032)
Small L&P	$ (425,269)	2,442,739,134	$ (0.00017)
Medium L&P	$ (369,405)	2,994,893,946	$ (0.00012)
E19	$ (583,539)	3,601,731,775	$ (0.00016)
Streetlights	$ (4,800)	67,140,990	$ (0.00007)
Standby	$ (0)	19,494,840	$ (0.00000)
Agriculture	$ (14,175)	749,789,118	$ (0.00002)
E20 T (Excluding FPP)	$ (12,326)	543,654,063	$ (0.00002)
E20 P (Excluding FPP)	$ (55,506)	1,400,539,917	$ (0.00004)
E20 S (Excluding FPP)	$ (22,892)	501,484,641	$ (0.00005)
Total	**$ (3,900,308)**	**19,781,718,725**	**$ (0.00020)**

Attachment A
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Proposed 2019 ERRA Forecast PCIA Rates Including 2018 Actual Brown Power True-up (with DWR Franchise Fee)

	Proposed PCIA Rates by Vintage										
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	0.02095	0.02439	0.02541	0.02663	0.02684	0.02686	0.02694	0.02683	0.02689	0.02697	0.02982
Small L&P	0.02134	0.02468	0.02568	0.02681	0.02700	0.02702	0.02708	0.02697	0.02703	0.02710	0.02920
Medium L&P	0.02239	0.02589	0.02692	0.02810	0.02830	0.02833	0.02839	0.02826	0.02833	0.02841	0.03054
E19	0.02078	0.02399	0.02495	0.02601	0.02620	0.02622	0.02627	0.02615	0.02621	0.02628	0.02807
Streetlights	0.01900	0.02171	0.02251	0.02334	0.02348	0.02349	0.02351	0.02339	0.02343	0.02350	0.02400
Standby	0.01658	0.01906	0.01980	0.02059	0.02073	0.02074	0.02078	0.02068	0.02072	0.02078	0.02180
Agriculture	0.01862	0.02158	0.02247	0.02349	0.02366	0.02368	0.02374	0.02364	0.02370	0.02377	0.02586
E20 T (Excluding FPP)	0.01773	0.02045	0.02126	0.02216	0.02231	0.02234	0.02237	0.02228	0.02233	0.02239	0.02386
E20 P (Excluding FPP)	0.01890	0.02182	0.02268	0.02365	0.02382	0.02383	0.02388	0.02377	0.02383	0.02390	0.02551
E20 S (Excluding FPP)	0.01980	0.02286	0.02376	0.02478	0.02496	0.02497	0.02503	0.02492	0.02497	0.02504	0.02676
System Average PCIA Rate by Vintage	0.01912	0.02209	0.02455	0.02433	0.02655	0.02697	0.02685	0.02667	0.02651	0.02661	0.02881

	Adjusted 2019 Forecast of Vintage Sales										
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Residential	58,817,639	16,249,497	364,477,237	767,825	160,684,492	1,184,674,713	4,753,883	2,858,695,925	969,700,325	7,460,250,301	
Small L&P	16,892,326	28,128,872	149,763,301	2,909,222	291,377,806	197,876,661	112,379,786	1,115,623,245	41,765,086	2,442,739,134	
Medium L&P	50,772,049	190,091,623	131,300,355	25,960,921	254,787,798	168,496,378	90,102,673	1,298,475,911	40,057,665	2,994,893,946	
E19	341,197,671	813,604,406	160,760,827	44,982,607	257,422,191	184,176,709	89,772,815	1,113,474,795	579,017,197	3,601,731,775	
Streetlights	2,450,065	219,654	2,352,651	-	7,436,939	8,346,427	223,974	22,159,216	13,261,110	67,140,990	
Standby	-	-	8,049	-	149,973	72,215	36,168	3,239,389	8,079,256	19,494,840	
Agriculture	71,789	1,972,356	6,494,976	451,780	869,063	62,866,240	1,604,829	59,054,272	46,489,726	749,789,118	
E20 T (Excluding FPP)	231,280,379	679,998,332	121,739,794	43,163,632	-	24,129,981	-	327,617,822	1,859,510	543,654,063	
E20 P (Excluding FPP)	260,280,385	344,890,103	182,203,163	25,513,977	120,494,235	59,927,830	15,360,376	340,209,911	93,625,635	1,400,539,917	
E20 S (Excluding FPP)	75,916,436	138,130,318	29,499,760	9,520,239	21,122,118	21,955,394	-	147,826,180	52,803,275	501,484,641	
Total	**1,037,678,739**	**2,213,285,160**	**1,148,600,113**	**153,270,204**	**1,114,344,615**	**1,912,522,546**	**314,234,505**	**7,286,376,664**	**9,088,634,200**	**12,539,743,309**	**36,808,690,055**

	PCIA Revenue											
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total	
Residential	$ 1,232,400	$ 396,298	$ 9,261,300	$ 20,445	$ 4,312,935	$ 31,817,841	$ 128,060	$ 76,706,052	$ 26,078,380	$ 201,223,970		
Small L&P	$ 360,481	$ 694,182	$ 3,845,296	$ 77,995	$ 7,867,667	$ 5,345,962	$ 3,043,054	$ 30,086,855	$ 1,128,763	$ 66,188,713		
Medium L&P	$ 1,136,707	$ 4,920,970	$ 3,535,201	$ 729,515	$ 7,211,277	$ 4,773,187	$ 2,558,063	$ 36,696,944	$ 1,134,811	$ 85,081,985		
E19	$ 7,091,163	$ 19,519,425	$ 4,010,483	$ 1,170,198	$ 6,744,911	$ 4,828,384	$ 2,358,341	$ 29,122,518	$ 15,176,769	$ 94,656,720		
Streetlights	$ 46,555	$ 4,768	$ 52,968	$ -	$ 174,617	$ 196,065	$ 5,266	$ 518,375	$ 310,773	$ 1,578,117		
Standby	$ -	$ -	$ 159	$ -	$ 3,109	$ 1,498	$ 751	$ 66,975	$ 167,392	$ 405,072		
Agriculture	$ 1,337	$ 42,559	$ 145,914	$ 10,612	$ 20,564	$ 1,488,475	$ 38,096	$ 1,395,967	$ 1,101,645	$ 17,819,602		
E20 T (Excluding FPP)	$ 4,099,805	$ 13,903,143	$ 2,588,227	$ 956,586	$ -	$ 539,011	$ -	$ 7,300,186	$ 41,519	$ 12,171,211		
E20 P (Excluding FPP)	$ 4,920,485	$ 7,524,656	$ 4,132,827	$ 603,528	$ 2,870,086	$ 1,428,267	$ 366,846	$ 8,088,024	$ 2,231,057	$ 33,471,759		
E20 S (Excluding FPP)	$ 1,503,127	$ 3,157,139	$ 700,964	$ 235,947	$ 527,207	$ 548,316	$ -	$ 3,683,780	$ 1,318,292	$ 12,555,033		
Total - ED Alternative	**$ 20,392,060.42**	**$ 50,163,138.42**	**$ 28,273,338.33**	**$ 3,804,825.25**	**$ 29,732,372.74**	**$ 50,967,006.77**	**$ 8,498,478.38**	**$ 193,665,676.23**	**$ 48,689,399.54**	**$ 525,152,180.01**	**$ 959,338,476**	
ERRA Advice Letter 5527-E as filed	**$ 20,844,624.98**	**$ 52,348,494.58**	**$ 29,651,103.16**	**$ 3,947,906.37**	**$ 30,955,221.68**	**$ 53,217,277.32**	**$ 8,798,464.46**	**$ 200,454,526.53**	**$ 246,333,077.09**	**$ 360,015,229.61**	**$ 1,006,565,926**	PG&E 5527-E
Total - ED Alternative	**$ 20,552,277.34**	**$ 50,537,772.98**	**$ 28,506,731.59**	**$ 3,833,025.56**	**$ 29,966,496.43**	**$ 51,415,703.27**	**$ 8,563,861.57**	**$ 195,290,408.42**	**$ 240,323,740.83**	**$ 358,827,020.71**	**$ 987,817,039**	PG&E Supplement - No Portfolio Cost True Up
Difference	**$ (292,347.64)**	**$ (1,810,721.60)**	**$ (1,144,371.57)**	**$ (114,880.81)**	**$ (988,725.25)**	**$ (1,801,574.05)**	**$ (234,602.89)**	**$ (5,164,118.12)**	**$ (6,009,336.26)**	**$ (1,188,208.90)**	**$ (18,748,887)**	
Total - ED Alternative	**$ 20,474,825.39**	**$ 50,350,559.21**	**$ 28,399,931.14**	**$ 3,818,986.41**	**$ 29,856,076.40**	**$ 51,223,477.56**	**$ 8,532,465.25**	**$ 194,567,919.03**	**$ 48,923,745.20**	**$ 527,574,762.83**	**$ 963,722,748**	Remove 2018 pro rata adjustment
Difference	**$ (77,451.95)**	**$ (187,213.78)**	**$ (106,800.45)**	**$ (14,039.15)**	**$ (110,420.03)**	**$ (192,225.70)**	**$ (31,396.33)**	**$ (722,489.38)**	**$ (191,399,995.62)**	**$ 168,747,742.13**	**$ (24,094,290)**	
Total - ED Alternative	**$ 20,392,060.42**	**$ 50,163,138.42**	**$ 28,273,338.33**	**$ 3,804,825.25**	**$ 29,732,372.74**	**$ 50,967,006.77**	**$ 8,498,478.38**	**$ 193,665,676.23**	**$ 48,689,399.54**	**$ 525,152,180.01**	**$ 959,338,476**	Correct Line Losses
Difference	**$ (82,764.96)**	**$ (187,420.79)**	**$ (126,592.81)**	**$ (14,161.15)**	**$ (123,703.66)**	**$ (256,470.79)**	**$ (33,986.86)**	**$ (902,242.80)**	**$ (234,345.66)**	**$ (2,422,582.82)**	**$ (4,384,272)**	

Summary	$ (36,326,825)	**Filed BPTU (5527-E)**
	$ (55,075,712)	**Supplemented BPTU (5527-E-A)**
	$ (83,554,275)	**CCA Revised BPTU (Fixing 5527-E-A)**

	Without DWR FF										
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Residential	0.02091	0.02435	0.02537	0.02659	0.02680	0.02682	0.02690	0.02679	0.02685	0.02693	0.02978
Small L&P	0.02130	0.02464	0.02564	0.02677	0.02696	0.02698	0.02704	0.02693	0.02699	0.02706	0.02916
Medium L&P	0.02235	0.02585	0.02688	0.02806	0.02826	0.02829	0.02835	0.02822	0.02829	0.02837	0.03050
E19	0.02074	0.02395	0.02491	0.02597	0.02616	0.02618	0.02623	0.02611	0.02617	0.02624	0.02803
Streetlights	0.01896	0.02167	0.02247	0.02330	0.02344	0.02345	0.02347	0.02335	0.02339	0.02346	0.02396
Standby	0.01654	0.01902	0.01976	0.02055	0.02069	0.02070	0.02074	0.02064	0.02068	0.02074	0.02176
Agriculture	0.01858	0.02154	0.02243	0.02345	0.02362	0.02364	0.02370	0.02360	0.02366	0.02373	0.02582
E20 T (Excluding FPP)	0.01769	0.02041	0.02122	0.02212	0.02227	0.02230	0.02233	0.02224	0.02229	0.02235	0.02382
E20 P (Excluding FPP)	0.01886	0.02178	0.02264	0.02361	0.02378	0.02379	0.02384	0.02373	0.02379	0.02386	0.02547
E20 S (Excluding FPP)	0.01976	0.02282	0.02372	0.02474	0.02492	0.02493	0.02499	0.02488	0.02493	0.02500	0.02672

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

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.	Application 14-11-007 (Filed November 18, 2014)
And Related Matters	Application 14-11-009 Application 14-11-010 Application 14-11-011

COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION ISSUING GUIDANCE TO INVESTOR-OWNED UTILITIES FOR CALIFORNIA ALTERNATE RATES FOR ENERGY/ ENERGY SAVINGS ASSISTANCE PROGRAM APPLICATIONS FOR 2021-2026 AND DENYING PETITION FOR MODIFICATION

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May 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
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Pursuant to Rule 14.3 of the California Public Utility Commission's ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE")[1] respectfully submits the following comments on the *Proposed Decision Issuing Guidance to Investor-Owned Utilities for California Alternate Rates for Energy/ Energy Savings Assistance Program Applications for 2021-2026 and Denying Petition for Modification* ("Proposed Decision") filed April 30, 2019.

[1] MCE is California's first operational community choice aggregation ("CCA") program and began providing retail electricity service to customers on May 7, 2010. Today, MCE provides retail electricity generation services to over 470,000 customer accounts within PG&E's service territory. These communities include Marin County and Napa County. It also includes unincorporated Contra Costa County, as well as the cities of Richmond, San Pablo, El Cerrito, Walnut Creek, Lafayette, Concord, Martinez, Oakley, Pinole, Pittsburg and San Ramon and the towns of Danville and Moraga. MCE also serves the city of Benicia in Solano County and MCE recently filed an Implementation Plan with the Commission to certify expansion into unincorporated Solano County.

I. INTRODUCTION

MCE appreciates the Commission's express focus in the Proposed Decision on "deeper energy savings and innovative program design for the multifamily sector"[2] under the Energy Savings Assistance ("ESA") Program for the 2021-2026 program cycle. The Commission authorized MCE in D.16-11-022, as modified by D.17-12-009, to run the Low-Income Families and Tenants ("LIFT") pilot program to serve income-qualified multifamily properties by leveraging general energy efficiency ("EE") programs and low-income energy savings programs.[3] The MCE LIFT pilot program has been offering technical assistance, rebates, and fuel switching opportunities from gas and propane to electric heat pumps to income-qualified multifamily property owners and residents since October 2017.

In the sections below, MCE provides comments on some of the proposals related to the Multifamily Whole Building Program ("MFWB") as described in the Proposed Decision and the *Guidance Document for the Energy Savings Assistance (ESA) and California Alternate Rates for Energy (CARE) Program Budget Applications for Program Years 2021-2026* ("Guidance Document") that is attached to the Proposed Decision.

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[2] Proposed Decision at 8

[3] Decision D.17-12-009, *Decision Resolving Petitions for Modification of Decision 16-11-022*, OP 148 at 506.

II. COMMENTS

A. The Commission Should Align the Concepts of "Program Administrator" and "Third-Party Implementer" for the Multifamily Whole Building Program with Existing Third-Party Program Rules

The Proposed Decision recommends moving to the concept of third-party program design and delivery for the ESA MFWB, consistent with the direction under the general EE programs.[4] MCE supports this proposal to encourage more innovation in MFWB programs. Furthermore, MCE encourages the alignment of ESA MFWB program rules with the ones for the general IOU EE programs to the extent possible to increase consistency between low-income and general EE programs and to reduce program complexities.

While MCE supports the third-party program design and delivery model for the ESA MFWB program, the Proposed Decision should be modified to eliminate some inconsistencies between the approach in the Proposed Decision and Guidance Document regarding the concepts of third-party delivery of the MFWB program and third-party delivery in the general EE programs.

Under the general EE third party programs, the terms "program administrator" ("PA") and "third-party implementer" have very specific meanings. The PA oversees the EE program portfolio and designates much of the program design and delivery to third-party implementers, which are different from traditional implementers because they are primarily responsible for program design.[5]

It is MCE's understanding that it is the intent of the Commission to institute third-party program <u>implementation</u> for the ESA MFWB program, not third-party program <u>administration</u>. This would ensure consistency with the general EE programs. MCE recommends the following

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[4] See Proposed Decision at 8 and Guidance Document at 2 and 18

[5] D.16-08-019 at p. 67-69.

modifications to the Proposed Decision and Guidance Document (additions are underlined, deletions are ~~struck out~~):

> "The Commission is specifically interested in a focus on deeper energy savings and innovative program design for the multifamily sector, including third party implementation ~~administration~~ (i.e., third party program design and delivery ~~implementation~~) of a low-income multi-family whole building energy efficiency program. This is consistent with the direction of the general IOU energy efficiency programs."[6]

> "The IOUs should propose alternative program design, including third party implementation ~~administration~~ of the ESA multifamily whole building program, in compliance with statutory budget requirements."[7]

MCE supports the movement to a third-party implementer approach for the MFWB while maintaining consistency with the third-party rules for general EE programs.

B. The Commission Should Avoid Proposing a Single Statewide Implementer for the Multifamily Whole Building Program

The Guidance Document states that "the IOUs are strongly advised to consider a statewide program with a single implementer" for the MFWB program.[8] The Commission should avoid recommending a single, statewide program implementer for the MFWB program as it is generally not appropriate for a downstream program to be implemented statewide. Downstream programs should be integrated and coordinated, and program leveraging has proven to be a successful tool in downstream program implementation in the multifamily context. For example, MCE's LIFT pilot for low-income multifamily properties has been successfully leveraging MCE's general EE Multifamily Energy Savings Program to maximize customer incentives, facilitate customer recruitment and streamline administrative processes. Implementing downstream programs

[6] Proposed Decision at 8
[7] Guidance Document at 2
[8] Guidance Document at 18

statewide risks splintering savings opportunities and increasing program delivery costs. Additionally, downstream programs involve customer touches and local needs that vary and require program tailoring. This is particularly true in the multifamily and low-income context where much of the eligible population can be considered "hard-to-reach." Finally, a single statewide implementer may not have adequate penetration in certain markets which risks segments of the low-income population being underserved.

This point of view is supported by the Commission's own decisions. The CPUC defined "statewide" in Decision 16-08-019 and highlighted that only certain types of EE programs are appropriate for statewide administration:

> "Upstream (at the manufacturer level) and midstream (at the distributor or retailer level, but not the contractor or installer level) interventions are required to be delivered statewide. Some, but not all, downstream (at the customer level) approaches are also appropriate for statewide administration."[9]

That decision also expressly rejected the concept of a statewide implementer, citing concern by parties that one entity may not be able to deliver all aspects of the program and determined that PAs should determine how many implementers are needed for a single program.[10]

For these reasons, MCE opposes the concept of a statewide program with a single implementer for the MFWB program. A preferable approach is for each PA to continue to be responsible for ensuring adequate third-party implementation throughout their low-income populations. Allowing for diversity in program design from implementers will promote innovation which will lead to stronger ESA MFWB programs over time.

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[9] Decision 16-08-019, *Decision Providing Guidance for Initial Energy Efficiency Rolling Portfolio Business Plan Filings*, at 111.
[10] D.16-08-016, at 51-52.

III. CONCLUSION

MCE thanks the assigned Administrative Law Judge Kwan MacDonald and Commissioner Rechtschaffen for their thoughtful consideration of these comments.

Respectfully submitted,
/s/ *Jana Kopyciok-Lande*

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May 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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REPLY COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION ISSUING GUIDANCE TO INVESTOR-OWNED UTILITIES FOR CALIFORNIA ALTERNATE RATES FOR ENERGY/ ENERGY SAVINGS ASSISTANCE PROGRAM APPLICATIONS FOR 2021-2026 AND DENYING PETITION FOR MODIFICATION

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May 28, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.	Application 14-11-007 (Filed November 18, 2014)
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Pursuant to Rule 14.3 of the California Public Utility Commission's ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE")[1] respectfully submits the following reply comments on the *Proposed Decision Issuing Guidance to Investor-Owned Utilities for California Alternate Rates for Energy/ Energy Savings Assistance Program Applications for 2021-2026 and Denying Petition for Modification* ("Proposed Decision") filed April 30, 2019.

[1] MCE is California's first operational community choice aggregation ("CCA") program and began providing retail electricity service to customers on May 7, 2010. Today, MCE provides retail electricity generation services to over 470,000 customer accounts within PG&E's service territory. These communities include Marin County and Napa County. It also includes unincorporated Contra Costa County, as well as the cities of Richmond, San Pablo, El Cerrito, Walnut Creek, Lafayette, Concord, Martinez, Oakley, Pinole, Pittsburg and San Ramon and the towns of Danville and Moraga. MCE also serves the city of Benicia in Solano County and MCE recently filed an Implementation Plan with the Commission to certify expansion into unincorporated Solano County.

I. REPLY COMMENTS

A. MCE Provides Additional Information About Its Low-Income Family and Tenants Pilot Program in Response to The Greenlining Institute's Opening Comments.

MCE appreciates the comments from The Greenlining Institute on MCE's Low-Income Family and Tenants ("LIFT") pilot.[2] In response to those comments, MCE provides additional details and clarifications on the reporting requirements, status, and proposed future of LIFT. Decision ("D.") 16-11-022, as modified by D.17-12-009 ("the LIFT Decision"), details MCE's reporting requirements for the LIFT pilot. The decision states:

> "We find it reasonable and direct MCE to file monthly progress reports, two interim reports with preliminary findings, report to the LIOB quarterly on its pilot, and submit a final report upon conclusion of the pilot, as proposed. These reports shall be filed with Energy Division."[3]

MCE has been submitting monthly and quarterly progress reports to Energy Division Central Files and the service list for the above-captioned proceeding since LIFT's launch on October 31, 2017. These reports provide updates on program metrics, including budget and expenditures, participating unit and heat pump count, energy savings, energy efficiency ("EE") measures implemented, and households treated. Pursuant to the LIFT Decision, MCE also submitted an interim report on the LIFT pilot to Energy Division Central Files and the above-mentioned service list on April 30, 2019. The interim report provides a more holistic picture of the successes and challenges of the LIFT pilot program to date and describes the status of program metrics established in MCE Advice Letter 23-E-A[4].

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[2] The Greenling Institute's opening comments, section II.f at 7

[3] *Administrative Law Judge's Ruling Providing a Clean Copy of the Modified Red-Lined Version of D.16-11-022* ("Clean Copy of D.16-11-022"), February 2, 2018, at 386

[4] MCE was ordered in D.16-11-022 to provide detailed program metrics which MCE submitted in Advice Letter ("AL") 23-E, *Identification of Metrics to Track Marin Clean Energy's Low-Income Families and Tenants Pilot* on April 6, 2017. This AL was supplemented by AL 23-E-A on July 20, 2017, which provided the updated and final metrics and revisions to the LIFT pilot.

1. MCE provides select findings to inform the ESA Guidance Decision's findings and future program design and development.

A few of the findings and lessons learned from MCE's LIFT interim report are useful to inform future program design and development of multifamily ESA programs and are therefore briefly mentioned here. First and foremost, MCE has found that timelines for implementing energy efficiency measures in the multifamily context are extremely long. For example, the timeline between a property showing interest in participating in a multifamily EE program and finalizing the scope of work can be up to 12 months. It then can take up to another 6 months to install the agreed-upon measures. Factors that contribute to extended timelines are that many stakeholders are involved in the decision-making process, EE upgrades are often coordinated with larger renovation projects, and property owners are often faced with time and resource constraints. Additionally, informed EM&V analyses can only be completed once sufficient time has passed to collect detailed program data, e.g., customer billing data for energy savings and bill impact analysis.

This delay between property interest, project implementation, and availability of empirical results demonstrates that timelines for implementing multifamily EE measures can be extensive. This should be considered when designing and developing future ESA programs. As such, MCE cautions against designing multi-family programs on a shorter timeframe under the ESA 2021-2026 program cycle as La Cooperative Campesina de California proposes in their comments on the Proposed Decision.[5]

[5] La Cooperative Campesina proposes that the Commission take a probationary approach introducing third-party administration, third-party implementers, and the Multifamily Whole Building Program. They also request the Commission to consider multi-program tracks that are funded for up to two-years for the purpose of collecting data to better inform future core design of ESAP. See comments of La Cooperative Campesina, section B, at 4

A second finding of the LIFT pilot program to date that may be beneficial in informing future program design is the fact that program outreach through Community Based Organizations has not proven to be the optimal outreach strategy for customer recruitment under LIFT. MCE has found that property managers and property owners are a more efficient and effective means to identify program participants because they are in the position to make decisions about EE upgrades for the entire property instead of having to work directly with individual residents to serve each unit.

B. MCE Requests the ESA Guidance Decision Authorize MCE to Extend the LIFT Pilot Via A Tier 2 Advice Letter Through the End of the Current Program Cycle.

In response to The Greenlining Institute's opening comments, MCE also takes this opportunity to provide more clarity on the envisioned future of the LIFT pilot program.[6]

MCE proposed LIFT as a two-year pilot program. The program launched in October 2017 and is scheduled to terminate at the end of October 2019. Due to the aforementioned extended timelines under the LIFT pilot program, MCE would like to continue to offer the program and enroll new customers under the existing LIFT pilot program beyond October 2019 through the end of the current ESA program cycle.[7] As The Greenlining Institute pointed out in its opening comments, the LIFT Decision allowed MCE to seek additional funding for future program years through a Petition for Modification ("PFM").[8] A PFM, however, is not a feasible option in this particular case as the review and approval of a PFM often takes 12 to 18 months.[9] For a two-year

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[6] The Greenling Institute's opening comments, section II.f at 7

[7] MCE does not request an extension of the current LIFT pilot program into the future 2021-2026 program cycle. As directed by D.16-11-022, MCE would use the Application process if it elects to extend the LIFT pilot on a more permanent basis into future ESA program cycles.

[8] The Greenling Institute's opening comments, section II.f at 7 and Clean copy of D.16-11-022 at 387.

[9] Clean copy of D.16-11-022 at 234

pilot program, it is impractical if not impossible to propose programmatic changes through PFMs under such a timeline.

For this reason, MCE hereby requests the Commission authorize MCE to propose an extension to the LIFT pilot via a Tier 2 advice letter.

II. CONCLUSION

MCE thanks the assigned Administrative Law Judge Kwan MacDonald and Commissioner Rechtschaffen for their thoughtful consideration of these reply comments.

Respectfully submitted,
/s/ *Jana Kopyciok-Lande*

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May 28, 2019

Docket No.: A.18-11-003

Exhibit No.: ______________

Date: April 5, 2019

AMENDED TESTIMONY OF BRANDON CHARLES ON BEHALF OF MARIN CLEAN ENERGY AND PENINSULA CLEAN ENERGY CONCERNING PACIFIC GAS & ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF COMMERCIAL ELECTRIC VEHICLE RATES

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state the name and business address of the testimony sponsor.

A. My name is Brandon Charles. I am a Senior Project Manager at MRW & Associates, LLC ("MRW").[1] MRW's business address is 1736 Franklin Street, Suite 700, Oakland, California.

Q. Please briefly describe your experience.

A. I have worked in the electric utility industry since 2008 and have conducted analyses on behalf of clients related to ratemaking, price forecasting, and other policy and economic issues. I have previously sponsored testimony before the Commission regarding a variety of issues, including testimony in each of the large California investor-owned utilities' most recent General Rate Case Phase 2 proceedings. I have also worked at Bloom Energy, where I analyzed electricity and natural gas market prices and trends, market strategy and size, and distributed energy project economics. I hold a bachelor's degree in economics from Dartmouth College.

Q. On whose behalf are you testifying?

A. This testimony is being provided on behalf of Marin Clean Energy and Peninsula Clean Energy ("Joint CCAs").

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to address Pacific Gas & Electric's ("PG&E") request for authorization to implement a new commercial electric vehicle ("C-EV") rate class and associated C-EV rates.

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[1] Mr. Charles's qualifications are provided in Attachment A.

Q. Which aspects of PG&E's proposed C-EV rates will you address?

A. My testimony focuses on PG&E's proposed Power Charge Indifference Adjustment ("PCIA") rates for C-EV customers, including the PCIA rate design and the potential revenue allocation implications of PG&E's proposed PCIA rates.

Q. Are PG&E's proposed PCIA rates within the scope of this proceeding?

A. The Assigned Commissioner's Scoping Memo and Ruling includes several issues within the scope of this proceeding. Issue number 4 addresses whether the interaction of PG&E's proposal with Community Choice Aggregators ("CCAs") is reasonable.[2] Within this general issue, the Scoping Memo clarifies that the following specific questions shall be addressed: "a. Is the calculation and assignment of the [PCIA] reasonable? b. How will it be ensured that CCA customers will be able to take advantage of the EV rates? c. How will CCA customers experience the proposed generation component of the subscription charge?" Both of the issues that I address below relate to the reasonableness of the calculation and assignment of the PCIA as proposed by PG&E.

Q. Please summarize the Joint CCAs' recommendations regarding PG&E's proposed C-EV rate design.

A. I am proposing two modifications related to the PCIA rates included in PG&E's proposed C-EV rates.

First, I am proposing an additional C-EV rate option that includes a time-differentiated PCIA rate design in order to (1) send a stronger price signal to customers regarding the best times to charge EVs relative to PG&E's proposed C-EV rates and (2)

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2 Assigned Commissioner's Scoping Memo and Ruling, February 14, 2019, p. 3.

allow for lower off-peak and super-off-peak C-EV rates to allow for increased potential fuel cost savings.

Second, I am proposing a balancing account to address potential cost shifts as a result of the PCIA rates proposed to be assigned to the new rate classes in this proceeding. PG&E's proposed use of existing medium and large commercial and industrial PCIA rates introduces the potential to over- or under-collect PCIA revenue from the new C-EV class relative to its cost of service until cost-based revenue allocators and PCIA rates can be established for the class in PG&E's 2023 GRC Phase 2 proceeding. To address this issue, I am proposing a balancing account that would track revenues collected from the C-EV class until that time and ensure that the revenue collected from each customer class is reasonably consistent with its cost of service.

II. PG&E'S C-EV RATE PROPOSAL

A. Backdrop for Rate Proposal

Q. Please summarize the backdrop for PG&E's C-EV rate proposal.

A. PG&E explains that "[a]fter the enactment of [Senate Bill] 350 (SB 350, 2015)," the Commission's guidance ruling noted utility "Transportation Electrification (TE) applications may propose projects to change the rate structures, including demand charges, that are currently in effect for EVs used in commercial applications…"[3] Stakeholders previously "identified the need for PG&E to propose EV charging rates" in PG&E's SB 350 Standard Review application process, and "PG&E committed to filing new commercial EV rate options at a future date, suggesting that this occur within 6-12

[3] Pacific Gas & Electric Company Commercial Electric Vehicle Rate Proposal Amended Prepared Testimony ("PG&E Amended Testimony"), February 26, 2019, pp. 1-9 – 1-10.

months of a decision on the Standard Review Projects, which subsequently was issued May 31, 2018."[4]

Q. Why is PG&E proposing C-EV rates?

A. In its SB 350 application (A.17-01-022), "PG&E identified several significant existing barriers to widespread transportation electrification, including vehicle operating costs. To accelerate widespread transportation electrification, operators of all types of vehicles, and associated charging infrastructure, must have opportunities to save on fuel costs compared to fossil fuels."[5] PG&E has also found that "the fuel cost barrier remains an issue in a variety of EV use cases."[6] More specifically, PG&E has identified barriers to adoption for the medium- and heavy-duty fleets (particularly transit buses), public fast charging, and multi-family residential charging,[7] and "[t]hrough this proposal…aims to address identified issues of costs to charge EVs for these and other commercial customer segments…"[8]

Q. How would PG&E's proposed C-EV rates address these barriers to adoption?

A. PG&E proposes new C-EV rates because its existing medium and large commercial and industrial rates are intended to serve large customers with loads that are different from EV charging loads. As a result, "[c]urrent rates' use of maximum and peak demand charges result in high costs for EV charging customers that have typically low load factors."[9] PG&E's proposed C-EV rates would replace the customer (i.e., fixed) and demand charges that are included in PG&E's medium and large commercial and

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[4] *Id.*, p. 1-10.
[5] *Id.*, p. 1-2.
[6] *Id.*, p. 1-2.
[7] *Id.*, p. 1-3.
[8] *Id.*, p. 1-8.
[9] *Id.*, p. 1-17.

industrial rates with a monthly subscription charge, and would incorporate a high differential between peak and off-peak energy charges in order to incentivize customers to shift usage out of PG&E's highest-cost hours of the day.[10]

Q. Why is PG&E proposing a new C-EV rate class rather than new rate options in an existing rate class?

A. PG&E states that it "is proposing a new rate class for C-EV customers because of the distinctly different load profiles and cost of service for this class, as well as the business needs of this rate class."[11] Moreover, the creation of this new rate class "allows PG&E to track the revenues associated with this new transportation-related load relative to the costs incurred for these customers. This tracking is necessary to allow for the review of the rate design and measure any resulting cost shifts that can then be addressed in PG&E's 2023 General Rate Case (GRC) Phase 2."[12]

Q. Why is the tracking of C-EV revenues necessary to ensure that any cost shifts can be measured and addressed in a future ratemaking proceeding?

A. PG&E's "CEV related costs and revenues are not currently included in PG&E's GRC revenue and cost allocations."[13] The reason for this situation is that PG&E's proposed C-EV rate class would be an incremental rate class, meaning that it is load that is not currently being served by PG&E and for which the proposed revenue is allocated "based on expected future cost of service, and is specifically designed to recover marginal generation, distribution and transmission costs, and the fixed distribution costs."[14] Thus,

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[10] *Id.*, p. 1-17.
[11] *Id.*, p. 2-1.
[12] *Id.*, p. 2-2.
[13] *Id.*, p. 2-2.
[14] *Id.*, p. 2-15.

the risk of a cost shift would exist until the C-EV class becomes a rate class within the total revenue allocation process typically done in PG&E's General Rate Case Phase 2 proceeding.[15]

B. PG&E's C-EV Rate Design Proposal

Q. Please describe the elements of PG&E's proposed C-EV rate design.

A. PG&E proposes separate rates for small and large C-EV customers. However, both sets of rates include similar rate structures. For both small and large C-EV customers, PG&E's proposed C-EV rate design consists of two major components: a monthly subscription charge and a volumetric energy charge.[16] The subscription charge component is billed on a dollars per month basis,[17] meaning that it is effectively a fixed monthly charge. The energy charges "have been designed to send significant price signals to customers to consume in the non-peak hours,"[18] and therefore include on-peak, off-peak, and super-off-peak time-of-use ("TOU") rates that are consistent throughout the year (i.e., do not include seasonal differentiation).[19] The energy charges are billed on a dollars per kWh basis.[20]

Q. What costs are included in PG&E's C-EV generation rates?

A. The generation energy charges "consist of the marginal generation cost by TOU [period] plus the [PCIA]."[21] PG&E's proposed peak period generation energy charge includes, in

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15 *Id.,* p. 2-15.
16 *Id.*, pp. 2-10 - 2-15.
17 *Id.*, pp. 2-10 and 2-13.
18 *Id.*, p. 2-11.
19 *Id.*, pp. 2-11 and 2-13.
20 *Id.*, pp. 2-11 and 2-13.
21 *Id.*, p. 2-11.

addition to the peak period marginal generation commodity cost, a portion of PG&E's fixed costs and PG&E's marginal generation capacity costs.[22]

Q. Please describe the fixed costs PG&E proposes including in its C-EV generation rate.

A. PG&E's fixed costs are "the difference between total generation costs and marginal revenues."[23] According to PG&E,

> [f]ixed generation costs include salaries of personnel who schedule or operate the generation system or manage generation contracts, and other costs that do not scale in a time-differentiated manner with kWh of generation energy or kW-yr of generation capacity… In addition, the so-called fixed generation costs include the above-market costs from long-term contracts that are included in the Power Charge Indifference Adjustment (PCIA). PCIA costs scale with kWh of generation but are not-time-differentiated, so they are not actually fixed costs but they do not impact the differential between peak and off-peak rates, being the same in all TOU periods.[24]

Q. If PCIA costs are not time-differentiated as stated by PG&E, does this mean that PCIA rates recovering those costs must not be time-differentiated?

A. No. As reflected in PG&E's proposed approach to recovering its fixed costs through the combination of a subscription charge and peak period energy charges, it is possible to recover these costs through a more nuanced rate design that is also structured to collect the appropriate amount of revenue.

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22 *Id.*, p. 2-11.

23 *Id.,* p. 2-8.

24 PG&E Response to Energy Division Data Request_01-Q01. See Attachment B.

Q. How are each of PG&E's generation cost subcategories incorporated in PG&E's generation rates?

A. PG&E allocates marginal generation capacity costs to each TOU period based on its system Peak Capacity Allocation Factor ("PCAF") proportions.[25] PG&E allocates fixed costs partly to its fixed monthly subscription charge and partly to its peak TOU period rate.[26] The generation subscription charge consists of the total fixed charges multiplied by the PCAF proportion in the <u>non-peak</u> TOU periods.[27] The peak PCAF portion of the fixed costs are collected through PG&E's peak TOU period energy charge.[28] The amount of PG&E's "PCIA costs that are part of bundled customers' generation rates are separately allocated [from other generation costs] and applied on an equal cents per kWh basis in order to provide indifference between PG&E and CCA customers."[29] Furthermore, PG&E's PCIA rate "is not weighted by TOU period and is the same for all periods."[30]

Q. How did PG&E develop its proposed C-EV PCIA rates?

A. PG&E has explained that it "based its NBC [Non-Bypassable Charge] rate values (including the PCIA) for the E-CEV-S rate on existing A-6 rates. Similarly, the NBC rates for E-CEV-L are based on existing E-19 rates."[31] Therefore, the dollar per kWh

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25 PG&E Amended Testimony, p. 2-11.
26 *Id.*, p. 2-11.
27 *Id.*, p. 2-10.
28 *Id.*, p. 2-11.
29 PG&E Response to Joint CCAs Data Request_02-Q02. See Attachment B.
30 PG&E Responses to Joint CCAs Data Request_02-Q03 and Q04. See Attachment B.
31 PG&E Response to Joint CCAs Data Request_01-Q03. See Attachment B.

PCIA rates included in PG&E's proposed small and large customer C-EV rates are the current rates as of the 2018 ERRA for the A-6 and E-19 rate classes, respectively.[32]

C. The PCIA rates in PG&E's C-EV rate design proposal are a missed opportunity to offer even stronger price signals and lower C-EV operating costs.

Q. Do you have concerns regarding PG&E's proposed C-EV rate design?

A. Yes. Given that the C-EV rates are intended to accelerate electric vehicle adoption and provide opportunities to reduce EV fuel costs, proposing a flat PCIA rate design (and a corresponding flat bundled rate PCIA component) is a missed opportunity.

Q. Why is the use of a flat PCIA rate design for C-EV customers a missed opportunity?

A. Adopting time-differentiated PCIA rates and correspondingly incorporating a time-differentiated PCIA component in bundled rates would allow for an even stronger price signal to avoid consumption during the highest cost hours of the day. This would be consistent with PG&E's goals by maximizing the potential for commercial EV customers to save on fuel costs compared to fossil fuels by charging during off-peak and super-off-peak hours whenever possible.

Q. If time-differentiated PCIA rates increased peak energy rates above those proposed by PG&E, could these rates potentially disincentivize commercial EV use for customers who are unable to completely avoid charging during peak hours?

A. Any potential disincentive could be avoided by initially offering this rate structure as an optional variant of PG&E's proposed C-EV rates.

[32] PG&E Responses to Joint CCAs Data Request_01-Q04 and Q05. See Attachment B.

Q. Why is it appropriate to implement such an optional C-EV rate design now, rather than to wait until PG&E's proposed rates have been in place for a number of years?

A. As discussed by PG&E, the load it expects to serve under its proposed C-EV rates is incremental to the load it is currently serving. Given that this market is immature and the revenue implications for PG&E and its other customers are relatively small,[33] now is the ideal time to provide customers with alternative rate design options that are, to the extent feasible, revenue neutral. Furthermore, the State of California has expressed great urgency in its efforts to electrify the transportation sector as part of its climate strategy, as evidenced by Executive Order B-48-18 setting zero-emission vehicle and EV charger targets.[34] Offering one rate structure with large TOU differentials would provide a stronger incentive to customers with the greatest flexibility in charging behavior to avoid high cost hours and, in exchange, benefit from lower fueling costs. Such an approach could complement PG&E's proposed rate design and lead to the most rapid adoption of commercial EVs possible.

Q. Would the use of such an optional rate design increase the likelihood of cost shifts due to PG&E's implementation of new C-EV rates?

A. No more than other elements of the proposed C-EV rates. While PG&E has done an admirable job estimating what this new rate class might look like in terms of load shapes

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[33] The revenue implications of the entire C-EV class are expected to be small relative to PG&E's overall customer base, meaning that optional rates can be implemented now with minimal risk to other customer classes. PG&E's medium and large commercial and industrial revenue as compared to its expected C-EV revenue illustrates this situation. PG&E's 2019 Annual Electric True-Up cost allocation to the A-6, A-10-S, E-19-S, E-19-P, E-20-S, and E-20-P (the otherwise applicable medium and large commercial and industrial rate group) is $1,934.5M, while PG&E's C-EV class cost allocation would be just $49.2M. See PG&E Table 2-1, p. 2-3 ($1,011.7M + $461.4M + $461.4M = $1,934.5M) and PG&E Table 2-2, p. 2-4 ($10.1M + 33.7M + $5.4M = $49.2M).

[34] PG&E Amended Testimony, p. 1-2.

and costs, in fact there is considerable uncertainty inherent in the costs and revenues that will ultimately be imposed on the system by, and collected from, the C-EV class. The most obvious example of this inherent uncertainty is that the proposed C-EV rates rely on PCIA rates developed for completely different rate groups (A-6 and E-19) with different loads and revenue allocations specific to the medium and large commercial and industrial rate class is. In addition, the same logic that PG&E applies to potential cost shifts due to other elements of its rates also applies to the PCIA: because the C-EV rate class is being established as an incremental rate class, any cost shift would be "a hypothetical cost shift that would only be realized when the rate class is allocated total revenues allocated among all classes in the 2023 GRC Phase II."[35] Thus, implementing a rate option that includes a time-varying PCIA now would allow for any cost shifting implications to be addressed along with the rest of the C-EV rate elements in PG&E's next GRC Phase 2, so long as an adequate mechanism for resolving PCIA over- or under-collections in PG&E's next GRC Phase 2 is adopted. Finally, the precise time-differentiated PCIA rates adopted could be modified as needed over time based on actual C-EV customer usage in order to maintain revenue neutrality.

D. PG&E's proposed PCIA rates risk cost shifts without adequate balancing account tracking.

Q. Do you have any concerns regarding potential cost shifts associated with PG&E's proposed C-EV rate design?

A. Yes. As discussed earlier in my testimony, PG&E has proposed directly applying the currently adopted PCIA rates for its medium and large commercial and industrial rate schedules to its proposed C-EV rate schedules (and incorporating an identical PCIA

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35 *Id.*, p. 2-15.

component in its bundled rates). For example, PG&E has proposed adopting current Schedule A-6 PCIA rates for C-EV customers. However, PG&E developed its medium and large commercial and industrial rates for an entirely different group of customers from its proposed new C-EV customer class. These classes could have considerably different loads and marginal costs. PG&E itself freely admits that the usage patterns and consumption levels for C-EV customers will not be similar to existing A-6 and E-19 customers.[36] As a result, I am concerned that these PCIA rates could ultimately be unfair by considerably over- or under-estimating the appropriate PCIA rates and resulting revenue for C-EV customers. This could result in significant cost shifts that would not be adequately addressed under PG&E's proposal. Collecting excess PCIA revenue from C-EV customers would be particularly harmful, as it would both unfairly burden these customers and undermine California's transportation electrification goals.

Q. Why has PG&E proposed adopting the PCIA rates for the A-6 and E-19 rate schedules for its proposed C-EV rates?

A. PG&E states that these are the appropriate PCIA rates to use because A-6 and E-19 are the alternative rate schedules for C-EV customers if they do not choose a C-EV rate option.[37] Thus, PG&E has selected PCIA rates from different rate schedules, each with a different cost basis and set of billing determinants compared to the C-EV customer class, in order to bill C-EV customers.

[36] PG&E Responses to Joint CCAs Data Request_02-Q05 and Q06. See Attachment B.
[37] PG&E Responses to Joint CCAs Data Request_02-Q05 and Q06. See Attachment B.

Q. What is the basis for your concern that PG&E's proposed C-EV PCIA rates could result in considerable cost shifts?

A. As noted above, PG&E does not expect that its small and large C-EV customers, respectively, will have similar usage patterns and consumption levels as A-6 and E-19 customers, respectively.[38] Given that PG&E's current A-6 and E-19 PCIA rates are based on customer class generation revenue allocations[39] and that rates established for each class to collect its respective share of the total revenue would be based on sales to each respective class, it is likely that these rates bear little resemblance to rates that would be appropriate for PG&E's C-EV rate schedules if actual usage data were available.

Q. Does PG&E propose a mechanism to track potential cost shifts resulting from its PCIA rates once actual usage data becomes available?

A. No. PG&E's testimony recognizes "the potential for cost shifting, specifically from the allocation of non-PCIA fixed generation costs and marginal generation capacity costs to the peak volumetric rate."[40] PG&E proposes a tracking mechanism for non-PCIA cost shifts, but it did not address potential PCIA cost shifts in its testimony.[41]

Q. Is PG&E capable of tracking revenue collected specifically from its C-EV PCIA rates?

A. Yes, PG&E is able to track PCIA costs and revenues from C-EV customers despite not proposing any specific rate modifications associated with tracked costs and revenues.[42]

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38 PG&E Responses to Joint CCAs Data Request_02-Q05 and Q06. See Attachment B.
39 D.18-10-019, p. 160, OP 4.
40 PG&E Amended Testimony, p. 2-15.
41 *Id.*, pp. 2-15 – 2-16.
42 PG&E Response to Joint CCAs Data Request_04-Q02. See Attachment B.

Q. How does PG&E claim that over- or under-collections of PCIA revenue from the C-EV rate class would be addressed?

A. PG&E claims that "in the event that an overcollection of PCIA occurs, the recent PCIA OIR decision provides for a true-up of PCIA related payments via a new balancing account (PABA) and all PCIA revenues from this customer class would flow into that BA and thus any overcollection would be reallocated back to customers…"[43]

Q. Does the PABA described by PG&E address your concern?

A. No. The PABA is intended to provide for an annual true-up of total PCIA costs and revenue[44] while maintaining indifference between different PCIA vintages and proper allocation of revenues and costs.[45] However, it is not designed to track revenues collected from a new, incremental rate class that is not part of the existing GRC Phase 2 revenue allocation and ensure that customers in the new rate class are not over- or under-billed relative to their cost of service over the course of several years. My concern relates to the potential for C-EV customers to pay significantly higher or lower PCIA rates than is appropriate for the C-EV rate class due to PG&E's reliance on PCIA rates developed for other rate groups in a different customer class until a more accurate set of rates can be established following PG&E's next GRC Phase 2. The PABA is not capable of addressing this concern because, as an annual true-up, it would reallocate revenues prior to the time that an adequate cost basis and associate revenue allocation would be established for the C-EV rate class. In other words, the PABA is not designed or

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43 PG&E Response to Joint CCAs Data Request_02-Q05. See Attachment B.

44 D.18-10-019, p. 124.

45 *Id.*, pp. 125-126.

intended to track revenue collection across a multi-year period and ensure inter-class equity over that period.

III. THE JOINT CCA RATE DESIGN PROPOSAL

Q. Is PG&E prohibited from introducing a time-differentiated PCIA rate in this proceeding?

A. To my knowledge, no Commission decision or California law explicitly prevents PG&E from doing so. PG&E has stated that it "did not consider, analyze or evaluate whether to distribute the collection of the PCIA by TOU period. The reason is that, by CPUC directive, the PCIA is a non-bypassable charge. Notwithstanding the non-bypassable nature of the PCIA the recent CPUC decision on the PCIA mechanism and rate design adopted the IOU's proposal to use the generation allocation factors for the customer class which account for patterns of use for each class."[46] This is not a compelling rationale, because the above-referenced decision addresses the proper allocation of PCIA costs between rate classes – not the specific design of the PCIA rate within a particular rate class.

PG&E has also claimed that it is out of scope to create new PCIA values for the C-EV class in this proceeding, and that such values should be determined in its ERRA proceeding.[47] However, the fact is that because the C-EV rate class is a new customer class, PG&E is by definition creating new PCIA rates by applying rates calculated for other customer classes to the C-EV class. Whether or not the rate value selected for the C-EV class appears on a different rate schedule is immaterial; all of the rates applying to

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[46] PG&E Response to Joint CCAs Data Request_01-Q10. See Attachment B.
[47] PG&E Response to Joint CCAs Data Request_04-Q01. See Attachment B.

C-EV customers are newly created rates for a newly created rate class. Moreover, PG&E has not established any rationale as to why the PCIA cannot be designed as a time varying charge for this new customer class.

Q. Is there a mechanism by which PG&E could reasonably allocate PCIA revenues to different time-of-use periods?

A. PG&E has described the above-market costs collected through the PCIA as effectively being a fixed cost that scales with kilowatt-hours of generation.[48] Thus, it would reasonable to treat these costs similarly to how PG&E proposes to treat other fixed costs while ensuring that they continue to be recovered - through energy charges that reflect kilowatt-hours sold to customers.

Q. Please describe how PG&E's proposal allocates fixed costs to different time-of-use periods.

A. As discussed earlier in my testimony, PG&E allocates fixed costs partly to its subscription charge and partly to its peak TOU period rate.[49] The subscription charge consists of the total fixed charges multiplied by the PCAF proportion in the <u>non-peak</u> TOU periods.[50] The peak PCAF portion of the fixed costs are collected through PG&E's peak TOU period energy charge.[51] The non-peak allocation factors that PG&E has used in allocating fixed costs for each of its three C-EV rate variants are shown in Table 1 below.

48 PG&E Response to Energy Division Data Request_01-Q01. See Attachment B.
49 PG&E Amended Testimony, p. 2-11.
50 *Id.*, p. 2-10.
51 *PG&E Amended Testimony*, p. 2-11.

Table 1: Non-Peak Allocation Factor Applied to Fixed Costs.[52]

	Non-Peak Allocation Factor
EV-Small	18%
EV-Large-S	12%
EV-Large-P	11%

Q. Could the same approach be applied to developing PCIA rates for the C-EV rate class?

A. Yes. The same allocation factors could be applied to allocate the total PCIA revenue expected under PG&E's proposed PCIA rates to peak and non-peak TOU periods. The results of doing so are presented in Table 2. The peak revenue can be translated into a rate by dividing the revenue by expected peak sales for each rate group. The non-peak revenue can be translated into a rate by dividing the revenue by expected non-peak sales, thereby allocating revenue between the off-peak and super-off-peak periods based on their relative share of non-peak sales.

Table 2: PG&E Non-Peak Allocation Factors Applied to PCIA Revenue[53]

	EV-Small	EV-Large-S	EV-Large-P
PCIA Revenue	$926,821	$1,365,551	$240,980
Non-Peak Allocation Factor	18%	12%	11%
Non-Peak PCIA Revenue	$168,791	$164,796	$27,550
Peak PCIA Revenue	$758,031	$1,200,755	$213,429

52 PG&E Workpapers. A1811003 PG&E Wpprs 2 2-27-19.xlsx, tabs "RA and RD (EV-Small),", "RA and RD (EV-Large-S)," and "RA and RD (EV-Large-P)," cell F42.

53 Note that apparent errors in non-peak and peak PCIA revenue amounts are due to rounding of the non-peak allocation factors.

Q. What do you recommend regarding PG&E's PCIA rate design for C-EV customers?

A. I recommend that the Commission adopt optional C-EV rates incorporating the methodology that I have described in this section of my testimony. As discussed earlier, adopting this approach to PCIA rate design on an optional basis will ensure that customers are not discouraged from adopting commercial EVs and making use of PG&E's C-EV rates by the large peak to non-peak rate differentials, but also have the opportunity to make use of the strongest incentives possible to adopt commercial EVs and charge during desirable hours of the day.

Q. Have you calculated the C-EV rates using the PCIA rate design methodology you have described?

A. Yes. Table 3, Table 4, and Table 5 below presents PCIA and total bundled rates along with the resulting peak versus off-peak and super-off-peak bundled rate differentials. This table also compares the Joint CCA proposed rates with PG&E's proposed rates.

Table 3: Comparison of Joint CCA and PG&E Proposed EV-Small Rates and Rate Differentials

	PCIA $/kWh		Total Bundled $/kWh		Peak Bundled Differential	
	Joint CCA Proposal	PG&E Proposal	Joint CCA Proposal	PG&E Proposal	Joint CCA Proposal	PG&E Proposal
Peak	$0.1225	$0.0247	$0.4009	$0.3030	N/A	N/A
Off-Peak	$0.0054	$0.0247	$0.0987	$0.1180	3.06	1.57
SOP	$0.0054	$0.0247	$0.0734	$0.0927	4.46	2.27

Table 4: Comparison of Joint CCA and PG&E Proposed EV-Large-S Rates and Rate Differentials

	PCIA $/kWh		Total Bundled $/kWh		Peak Bundled Differential	
	Joint CCA Proposal	PG&E Proposal	Joint CCA Proposal	PG&E Proposal	Joint CCA Proposal	PG&E Proposal
Peak	$0.0761	$0.0210	$0.3577	$0.3027	N/A	N/A
Off-Peak	$0.0034	$0.0210	$0.0931	$0.1108	2.84	1.73
SOP	$0.0034	$0.0210	$0.0711	$0.0888	4.03	2.41

Table 5: Comparison of Joint CCA and PG&E Proposed EV-Large-P Rates and Rate Differentials

	PCIA $/kWh		Total Bundled $/kWh		Peak Bundled Differential	
	Joint CCA Proposal	PG&E Proposal	Joint CCA Proposal	PG&E Proposal	Joint CCA Proposal	PG&E Proposal
Peak	$0.0766	$0.0210	$0.3508	$0.2953	N/A	N/A
Off-Peak	$0.0032	$0.0210	$0.0902	$0.1081	2.89	1.73
SOP	$0.0032	$0.0210	$0.0688	$0.0866	4.10	2.41

Q. Do your proposed rates assume the same load profiles incorporated in PG&E's proposed C-EV rates?

A. Yes. Given that this is an entirely new rate class and that PG&E's billing determinants are projected incremental loads, there is no basis for assuming that the load profiles for my proposed rate options would be significantly different from those used by PG&E to develop its proposed rates at this time. If data collected once PG&E implements C-EV rates indicates otherwise, the rates can be adjusted as needed at that time to ensure revenue neutrality as compared to PG&E's proposed rate design. Moreover, adopting a balancing account for C-EV PCIA revenues as discussed in Section IV of my testimony, below, would provide additional assurance that the C-EV class as a whole would ultimately pay the correct amount of revenue.

IV. THE JOINT CCA PCIA BALANCING ACCOUNT PROPOSAL

Q. Please state your concerns with PG&E's proposed PCIA rates.

A. As discussed in Section II.D of my testimony, I am concerned that PG&E's proposed PCIA rates could ultimately be unfair by considerably over- or under-estimating the appropriate PCIA rates and resulting revenue for C-EV customers. This could result in significant cost shifts that would not be adequately addressed under PG&E's proposal.

Q. Could customers of certain rate groups be at relatively greater risk due to PCIA cost shifting?

A. It appears highly unlikely that the C-EV rate class will become as large as PG&E's medium and large commercial and industrial rate class prior to PG&E's 2023 GRC Phase 2, meaning that the total load in the C-EV rate class will almost certainly be lower. As a result, a shift of revenue is likely to have a greater impact on C-EV PCIA rates than on commercial and industrial PCIA rates. Lack of attention to this issue could, therefore, harm the ability of C-EV rates to provide fuel cost savings and accelerate the deployment of commercial EVs in California.

Q. Has PG&E proposed measures to address this issue?

A. In a way, while PG&E's primary position is that it cannot create a new C-EV PCIA rate in this proceeding, it has also indicated that a potential mitigation measure could be to develop a rate based on a prorated C-EV share of the current generation allocation for the otherwise applicable medium and large commercial and industrial rate schedule.[54] For example, the C-EV-Small PCIA rate would be based on the ratio of C-EV-Small generation revenue to A-6 generation revenue.[55]

Q. What is the result of PG&E's mitigation methodology?

A. Under PG&E's mitigation methodology, C-EV-Small customers would pay an 11% lower PCIA than under PG&E's current A-6 PCIA rate, which "reflects the fact that CEV customers have more off-peak usage [compared with A-6 customers]."[56] This result underscores my concern that simply applying PCIA rates developed for other customer classes could produce inequitable results for C-EV customers.

Q. Is PG&E's mitigation methodology adequate?

A: No. It is certainly a more reasonable starting point for PCIA rates applied to these customers, but still relies on uncertain assumptions that are very likely to prove incorrect. Even under this approach, C-EV customers could over pay PCIA rates (whether in separate PCIA rates charged to CCA and direct access customers or as part of their bundled rates), which could discourage C-EV rate adoption.

Q. How should PG&E address your concerns regarding its proposed PCIA rates?

A. PG&E should establish a C-EV PCIA balancing account to track PCIA revenues collected from C-EV customers until accurate PCIA rates can be set for the C-EV customer class, and to ultimately dispose of any positive or negative balances.

Q. What is the purpose of the C-EV PCIA balancing account?

A. This balancing account should ensure that C-EV customers pay an appropriate amount

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54 PG&E Response to Joint CCAs Data Request_04-Q01. See Attachment B.

55 *Id.*

56 *Id.*

toward the total PCIA revenues that PG&E must collect to maintain customer indifference. As noted above, while the PABA would address overall over- or under-collections of PCIA revenue, it would not address whether C-EV customers are over- or under-paying as a result of being billed under PCIA rates developed for different rate groups. Thus, the new C-EV PCIA balancing account would ultimately help ensure ratepayer indifference.

Q. How should PG&E structure the C-EV PCIA balancing account?

A. This balancing account should track PG&E's total PCIA revenue and PCIA revenue collected from C-EV customers until a cost-based share of revenue allocation can be established for these customers. As discussed by PG&E, the process to establish this allocation of revenue would not occur until PG&E's 2023 GRC Phase 2 under typical procedures.[57] The C-EV rate class's generation revenue allocation established in that proceeding would be a reasonable approximation of its appropriate share of total PCIA revenue. Thus, at that time PG&E could establish the degree (if any) to which PCIA revenue collected from C-EV customers diverges from what is appropriate. PG&E would then credit C-EV customers in future rates if a positive balance exists or collect addition revenue from C-EV customers in future PCIA rates if a negative balance exists.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

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[57] PG&E Amended Testimony, p. 2-15.

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

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Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	))))))	Rulemaking 16-02-007 (Filed February 11, 2016)

OPENING COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION

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April 8, 2019

For:
The California Community Choice Association

TABLE OF AUTHORITIES

California Public Utilities Commission Decisions

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	Rulemaking 16-02-007 (Filed February 11, 2016)

OPENING COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE PROPOSED DECISION

In accordance with Rule 14.3 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the California Community Choice Association ("CalCCA") respectfully submits the following comments on the *Proposed Decision of ALJ Fitch Adopting Preferred System Portfolio and Plan For 2017-2018 Integrated Resource Plan Cycle* ("Proposed Decision" or "PD"). For the reasons set forth below, CalCCA respectfully requests that the Commission adopted the changes to the PD set forth in Appendix A to these comments.

I. CALCCA AND ITS MEMBERS ARE COMMITTED TO CONTINUE WORKING WITH THE COMMISSION TO DEVELOP A ROBUST AND FUNCTIONAL IRP PROCESS

CalCCA and its members strongly support the Commission's efforts to develop a robust and functional Integrated Resource Planning ("IRP") process to produce a statewide portfolio that accurately identifies optimal resources and provides sufficient detail regarding these resources to inform load serving entity ("LSE") procurement. As the Commission recognized in Decision ("D.") 18-02-018, with a few narrow exceptions, a Community Choice Aggregator's ("CCA") actual procurement decisions, customer rates, and contract terms are the sole domain of the CCA's governing board.[1] At the same time, the Legislature has vested in the Commission a critically important statewide planning function.[2] CalCCA recognizes that for the IRP process to succeed, the Commission needs all LSEs, including CCAs, to provide it with individual IRPs that include the information that it reasonably needs to develop its aggregated statewide portfolio, identify potential resource gaps, and assess the statewide portfolio for compliance with the IRP goals listed at Public Utilities Code Section 454.52(a),[3] subject to reasonable confidentiality protections.

CalCCA supports the PD's approach to criteria pollutant emissions reporting. CalCCA recognizes that the Commission needs this information to assess its aggregated statewide portfolio for compliance with Section 454.52(a)(1)(H), and supports the re-submission of nonconforming IRPs via a Tier-2 advice letter.[4]

A successful IRP process should result in an optimal portfolio that: 1) is highly accurate, providing a high degree of confidence that the optimal resources identified in the portfolio are actually the optimal resources in the real world; and 2) provides sufficiently granular information to inform LSE procurement decisions. Such success will depend on the accuracy of the inputs and assumptions used to develop the portfolio. During this IRP process, some CCAs informed the Commission that they possessed local information and projections that were significantly more accurate than those being used in IRP, and some CCAs cautioned against using less accurate IRP portfolios for planning purposes.[5] These statements demonstrate the CCAs' dedication to developing the most accurate and effective IRP process possible. In the next IRP

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1 D.18-02-018 at 26.
2 *Id.*
3 All further references to statute are to the California Public Utilities Code unless otherwise noted.
4 PD at 22-23.
5 PD at 17.

cycle, the Commission should develop a mechanism for incorporating more accurate local information into its modeling inputs and assumptions when such information is available.

II. CCAS CAN BE COUNTED ON TO DRIVE THE PROCUREMENT NEEDED TO ACHIEVE THE SB 350 GOALS

A. The CCAs are able and willing to procure the needed resources

As the PD recognizes, "CCAs are the LSEs with the vast majority of planned new resource purchase through 2030, reflecting their expectation of growing load."[6] CCAs plan to procure over 10,000 MW of new renewable resources, over 90% of the new renewable procurement between now and 2030.[7] At the same time, the PD notes some concerns regarding CCAs' willingness and ability to procure these needed resources.[8] These concerns are misplaced. Although procuring over 10,000 MW of new renewable resources over the next 11 years is going to be a significant task, *the State's CCAs are up to this challenge*, and will continue to deploy their demonstrated capabilities to procure optimal resources at scale. The Commission can best ensure the success of this effort by: 1) adopting the collaborative approach outlined in D.18-02-018, respecting and balancing the Commission's statewide planning function and "the role of individual CCA governing boards to direct an individual CCA's procurement;"[9] and 2) providing CCAs with a statewide portfolio of optimal resources, developed through a high-confidence process, that includes actionable locational, resource attribute, and procurement timing information. The accelerating rate of CCA procurement is consistent with meeting and exceeding the annual additions of 900 MW capacity that target implies.

The CCAs' intent to procure the needed optimal resources is demonstrated in their individual IRP submissions, which collectively proposed over 10,000 MW of new storage,

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[6] PD at 88.

[7] PD at 89.

[8] PD at 102-104 (expressing concern regarding CCA participation in the Commission's IRP process and potential conflicts with local planning efforts); 130-131 (expressing concern regarding feasibility of relying on CCAs to procure the needed resources).

biomass, geothermal, and wind resource procurement.[10] The CCAs' ability and willingness to procure large-scale, long-term renewable projects is clearly established by their recent track record. By November, 2018, a subset of just 6 CCAs had *already* contracted for over 2,000 MW of new renewable resources.[11] Most of this procurement has been through *long term contracts* – the MW weighted average CCA contract is for over 17 years, with over 75% of CCA MW procurement occurring through contracts of 15 years or longer.[12] This includes such large projects as:[13]

- PCE Wright Solar Park (200 MW, 25-year PPA).
- PCE Mustang Two Solar Project (100 MW, 15-year PPA).
- MCE Little Bear Solar (160 MW, 20-year PPA).
- CPSF San Pablo Raceway solar (100 MW, 22-year PPA).
- SCP Sand Hill C wind (80 MW, 20-year PPA).
- SVCE/MBCP PPAs for 278 MW solar and 85MW/340MWh storage in California and 200 MW of wind in New Mexico.

Much of this procurement has come from large-scale projects – as of November, 2018, CCAs had contracted for 24 projects of 10 MW or more.[14] Although the PD notes some concern that the median CCA project size is 1.75 MW,[15] this number is skewed by the PD's use of the *median* rather than the *mean* (average) project size. The median CCA project size also likely reflects CCAs' procurement of more small-scale renewable projects to meet individual CCAs' local procurement and disadvantaged communities ("DAC") investment goals. CalCCA also agrees with the PD's suggestion that CCA programs pool resources and expertise for their procurement efforts,[16] and notes that CCA programs are *already* doing just that.[17]

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9 D.18-02-018 at 26.
10 PD at 89.
11 Data available at: https://cal-cca.org/wp-content/uploads/2018/11/CCA-Renewable-Energy-Map-web-1.pdf
12 *Id.*
13 *Id.*
14 *Id.*
15 PD at 131.
16 *Id.*

CalCCA's members are positioned to continue accelerating the pace of new renewable resource procurement. Procuring 10,000 MW of capacity by 2030 is a significant task and will require an average procurement rate of roughly 900 MW of new capacity per year from 2019 through 2030. CCAs, however, *already* procuring new renewable resources at a significant rate. Just two of the State's 20 CCA programs, Marin Clean Energy and Sonoma Clean Power had a combined 408.05 MW of new renewable resources come online in 2018.[18] CalCCA anticipates that the annual rate of CCA procurement will quickly accelerate to well over 900 MW per year as the State's other 18 CCA programs, including new large programs like Clean Power Alliance, procure new renewable resources at scale. This acceleration will also be driven by a number of other factors, including: growing CCA customer demand; the need to procure more RPS resources; the expiration of NBCs; downward trends in the cost of new renewable projects; and improvements in the accuracy and actionability of the Commission's identification of optimal resources in future IRP iterations.

B. CCAs require less lead-time for procurement than IOUs

In D.18-02-018, the Commission recognized the energy division's conclusion that "there is no 'need' on a reliability basis or for the greenhouse gas ("GHG") emissions reductions from renewables until around 2026, according to the modeling analysis."[19] Despite this, the PD expresses concern regarding the CCAs' ability to procure adequate resources in time to meet system needs.[20] This concern appears to be driven largely by renewable project lead-time assumptions that apply to the IOUs, not CCA programs. While IOUs generally take several years to complete large-scale renewable projects, CCAs' projects do not undergo a lengthy

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17 See, e.g., the joint SVCE/MBCP project listed above. Additionally, EBCE, PCE, MBCP, SJCE and SVCE have issued an RFP for Joint CCA RA Portfolio Management Services.

18 Data available at: https://cal-cca.org/wp-content/uploads/2018/11/CCA-Renewable-Energy-Map-web-1.pdf

19 D.18-02-028 at 99.

20 PD at 130-131.

Commission approval process, and generally have a much shorter turn-around time from the issuance of a request for offers ("RFO") to project operational date. For instance, Marin Clean Energy has two long-term contracts for large renewable projects in the 100 MW range that are now operational. For these projects, the average time from the issuance of the RFO to the completed project's operational date was *only 2 years, 8 months*.

C. The CCAs are the optimal entities to drive SB 350 procurement

For a number of reasons, CCAs are the most reliable option in many important respects for procuring the resources needed to achieve SB 350s goals. First, of the LSEs, CCAs' individual interests are best aligned with SB 350's goals. CCAs are *public agencies* and are bound by state policy goals, including SB 350. In addition, many CCA programs have internal GHG-reduction, renewable resource, and DAC development goals that are even more ambitious than SB 350. Unlike investor owned utilities ("IOU"), these CCA programs' duty to serve their customers and achieve the State's goals are not complicated by the need to maximize shareholder profits. Second, in light of recent developments, CCAs are among the most stable and reliable procurement entities. Unlike the IOUs, no CCA is currently in bankruptcy or under criminal probation (PG&E), no CCA is facing significant credit downgrades (PG&E and SCE), and no CCA has publicly announced its intent to stop providing generation service (SDG&E). Third, In light of PG&E and SCE's recent credit downgrades and the highly favorable terms available for municipal financing, CCA programs are positioned to get financing for new renewable projects that is equal to – or better than – the terms available to other entities. Fourth, as detailed above, CCAs are able to procure resources significantly more quickly than IOUs.

D. CCA customers are directly and indirectly procuring their share of reliability resources.

CCAs are committed to maintaining grid reliability and have already contributed significantly to system needs through a range of mechanisms. The PD expresses the concern that

CCAs may not be shouldering their burden of procuring their share of reliability resources, particularly existing fossil resources.[21] This concern is unfounded, as CCA customers pay for a significant share of the reliability resources contracted or owned by the IOUs through non-bypassable charges ("NBC"), including the Cost Allocation Mechanism ("CAM"). By not recognize this reliablity contribution by CCA customers, the current IRP process creates the artificial impression that CCAs are contributing to a reliability resource shortfall. In addition, neither the PD nor the IRP modeling account for the recently adopted multi-year RA requirement for all LSEs, which should significantly increase the amount of reliablity resources procured by CCAs.

III. THE COMMISSION SHOULD DEFER CONSIDERATION OF IOU PROCUREMENT TO FUTURE IRP ITERATIONS

The PD would order the opening of a new procurement track in this IRP cycle to explore procurement of new and existing resources for maintaining reliability and facilitating renewable integration.[22] Although the Commission does not have the authority to direct CCA procurement, costs associated with IOU-procured reliability and renewables integration resources, may, under some circumstances, qualify for recovery through NBCs (subject to self-provision options), and thus may directly impact CCAs and their customers. Moving forward with concrete procurement decisions based on the 2017-2018 IRP process and, particularly, the PD's Preferred System Portfolio ("PSP") would be imprudent and ultimately counterproductive. As such, CalCCA asks that the Commission defer any consideration of concrete IOU procurement to the 2019-2020 IRP cycle. If the Commission decides to move forward with a procurement-focused track in the 2017-2018 IRP proceeding, that track should focus on finding ways to improve the IRP process

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21 PD at 132.

22 PD at 136-137.

and make the Commission's preferred portfolio more accurate and actionable for procurement efforts.

It would not be prudent for the Commission to consider authorizing or ordering IOU procurement or NBCs based on the results of the 2017-2018 IRP process. First, as noted in D.18-02-018, the Energy Division designed this iteration of the IRP process as a *trial run* intended to "demonstrate the feasibility of the proposed process," not a platform for actual procurement decisions.[23] Throughout this process the Energy Division and parties have identified numerous flaws in the inputs, assumptions, forms, and modeling methodologies being used.[24] and identified these as issues for improvement in the 2019-20 cycle. For example, the estimated GHG emissions for the CAISO area from the Hybrid Conforming Portfolio ("HCP") varied from exceeding the GHG targets by only 3%[25] to over 24%,[26] depending on the model and assumptions deployed. This sensitivity to assumptions and approach suggests that any model output has limited accuracy and that the true emissions at best can be said to lie within 20% of

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23 D.18-02-018 at 15.

24 Staff have recommended RESOLVE assumptions of the carbon intensity of NW imports, which have a significant impact on the model results, the dispatch profiles of natural gas resources, and other assumptions. In addition, using more accurate local historical load data, better incorporating demand response and other DER, more granular analysis, more granular data about natural gas retirements, and accounting for health impacts may significantly shape model outcomes, among other improvements, *See, e.g.*, Energy Division Staff presentation "*Proposed Preferred System Portfolio for IRP 2017-18: System Analysis and Production Cost Modeling Results*" January 7, 2019, at 55 &102, available at: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Attachment%20A_Proposed%20Preferred%20System%20Portfolio%20for%20IRP%202018_final.pdf

25 *See,* CAISO PLEXOS model, scenarios 2 and 3, showing GHG emissions of 35.1 MMT based on more detailed gas dispatch assumptions and California Air Resources Board methodologies for estimating carbon intensities of Northwest imports. See, CAISO presentation "Reliability Assessment of the IRP Conforming Portfolio" Presented January 7, 2019, available at: http://www.cpuc.ca.gov/ uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/ Energy/EnergyPrograms/ ElectPowerProcurementGeneration/irp/2018/4.%20CAISO%202017-18%20IRP%20HCP%20 Analysis_01032019.pdf

26 *See* Energy Division SERVM model results, Energy Division Staff presentation "Proposed Preferred System Portfolio for IRP 2017-18: System Analysis and Production Cost Modeling Results" January 7, 2019, at 89. Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/ UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Attachment%20 A_Proposed%20Preferred%20System%20Portfolio%20for%20IRP%202018_final.pdf

the numeric estimate. Failure to recognize the variation would imply a false level of precision and accuracy in the model results that the data do not support.

IRP was intentionally designed to be an iterative process, with each iteration correcting the flaws and building on the successes of the previous IRP cycle. Given the number of issues raised in this initial, trial iteration, it is impossible have confidence whether the identified shortfalls are realistic results or mere modeling artefacts resulting from unverified assumptions and faulty data inputs. Thus, it would be far more prudent to defer binding procurement decisions until these flaws can be remedied in the next cycle.

Second, it would be neither appropriate nor prudent to authorize IOU procurement or NBCs based on the PSP selected by the PD. In accordance with the process required by D.18-02-018,[27] the LSEs spent months developing their individual portfolios, and the Energy Division then spent months aggregating these individual portfolios and assessing and adjusting the aggregated portfolio to develop the HCP. The PD, however, would reject the HCP and instead adopt a modified version of the reference system portfolio ("RSP") as its PSP.[28] This PSP does not provide an adequate basis for procurement decisions. The PSP was not developed according to the process outlined in D.18-02-018.[29] The PSP does not reflect individual LSEs' procurement preferences or any of the other information provided in their individual IRPs. The PSP is based on the RSP, which was intended to be the *starting point* for this *trial run* of the IRP process, not a final product. The PSP incorporates two major modifications to the RSP – the adoption of 2017 IEPR assumption adjustments and the adoption of a 40-year fossil fuel retirement assumption.[30] The incorporation of out-of-date assumptions from the 2017 IEPR is

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27 D.18-02-018 at 21-22. See also D.18-02-018, Attachment A.
28 PD at 106.
29 D.18-02-018 (Attachment A).
30 PD at 106-110.

not supported by the record, and parties have not had the opportunity to comment on this specific portfolio, raising both evidentiary and due process concerns.

Further, the PD's adoption of the PSP over the HCP appears to be driven, in part, by the erroneous finding that "all of the LSEs collectively showed a deficiency in the area of reliability… resources necessary to achieve the 2030 reliability needs of the system."[31] This finding is contradicted by the Energy Division's modeling of the HCP, which concluded that the HCP (based on parties' aggregated resource preferences) would result in a 2030 portfolio that is orders of magnitude more reliable than the accepted industry standard.[32] In contrast, the PD's PSP has not been modeled for reliability, leaving the PD to "infer" that the PSP will yield "acceptable system reliability results" based on the modeling of other portfolios.[33] Furthermore, given the substantial variation among the output of various models, there is scant basis for concluding that the PSP actually has lower GHG emissions than the HCP, since the relative difference between the two portfolios (3% difference in SERVM) is much lower than the relative differences among model outcomes (over 20% difference between the PLEXOS estimate of HCP emissions in the CAISO area and the SERVM estimate).

Third, emerging reliability needs are not imminent, thus allowing time for an iterative process to address such needs with non-fossil fuel resources. Based on its extensive modeling, the Energy Division has concluded that *no new IRP resources are needed until 2026*,[34] and there is little record evidence that supports any claim of an immediate or medium-term need for IRP procurement. Further, roughly 90% of the needed IRP procurement is to be done by CCAs. As discussed above, CCAs require significantly less lead time (roughly 3 years) to bring large new

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31 PD at 156 (Finding of Fact 16).

32 Administrative Law Judge's Ruling Seeking Comment on Preferred System Portfolio And Transmission Planning Process Recommendations (January 11, 2019), Attachment A at 60 (defining a "reliable system" as one with a Loss of Load Expectation of less than 0.1), 67 (the HCP has an expected LOLE of 0.003).

renewable projects from RFO issuance to operation, meaning that there is ample time for procurement before the 2026 need arises.

Fourth, the PD's PSP is of only limited utility for making actual IOU procurement decisions. Deferring procurement until the 2019-2020 IRP cycle will allow the Commission to refine its portfolio to provide better guidance as to the resources needed, including:

- Specific resources to be replaced or retired, with a focus on the most polluting resources located in DACs.
- Specific resources available with attributes.
- Specific local needs.
- Optimal timing of resource retirement and procurement (recognizing the different timelines for CCA and IOU procurement).
- Optimal locations of new resources.

IV. THE CCAS LOOK FORWARD TO REFINING THE RELATIONSHIP BETWEEN THE COMMISSION'S COORDINATION ROLE AND CCA PROCUREMENT AUTHORITY

A. The PD's assertive approach to CCA procurement is premature given the current need for a cooperative and iterative planning process.

SB 350's IRP guidelines and AB 117's role for CCAs in the California energy market provide a legislative framework that seeks to balance the essential role of the Commission's statewide planning process with other interests, including local choice. In D.18-02-018 the Commission expressly recognized this framework, stating that it "…respect[s] the separate authority of the CCA governing boards and the limitations on our rate and contract authority for [CCAs]"[35] and that "…with some exceptions related to renewable integration resources, the procurement decisions, customer rates, and contract terms and conditions (outside of the RPS) are the domain of the CCA governing boards and not the Commission."[36]

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33 PD at 107.
34 D.18-02-028 at 99.
35 D.18-02-018 at 158.
36 D.18-02-018 at 26.

Based on concerns regarding CCA programs' willingness and ability to procure the resources required to achieve SB 350s goals, in its discussion section the PD includes a handful of suggestions that do not appear to be consistent with SB 350 and AB 117's carefully crafted framework.[37] In light of the CalCCA and its members' support for a robust IRP process and the CCAs' demonstrated willingness and ability to provide the Commission that it needs for its statewide planning process and to procure the optimal resources needed to achieve SB 350s goals, these assertions are unnecessary and ultimately counterproductive to the goal of a prudent and collaborative IRP process.

B. The PD includes factual and legal errors in its statements on CCA renewable integration procurement.

The PD states that: "SB 350 specifically gave the Commission the authority to require CCAs to procure, via long-term contracts, renewable integration resources. At this moment in time, every resource that requires procuring or retaining, including the renewables themselves, is being used for renewable integration, since renewables are becoming the dominant resources in the electric system."[38] In addition, Conclusion of Law 18 of the PD states that: "The Commission should consider exercising its authority to require long-term commitments to renewable integration resources by CCAs in a new 'procurement track' of this IRP proceeding."[39]

The Commission should correct these erroneous statements. As the Commission itself noted in D.18-02-018, the overall IRP process is designed to achieve its intended GHG targets and ensure a safe, reliable, and cost-effective electricity supply in California *while respecting the*

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37 PD at 17-18 (CCA internal planning processes); 19 (CCA costs and rates); 136-137 (implying the authority to authorize IOUs to procure on behalf of CCA customers); 128-130 (the Commission's IRP process is "intended as the venue for both planning and for any procurement that should emanate from the analysis conducted during planning").

38 PD at 133, 158 (Findings of Fact 32 and 35).

39 PD at 161 (Conclusion of Law 18).

role of individual CCA governing boards to direct an individual CCA's procurement.[40] SB 350 does not give the Commission the authority to *order* any CCA procurement, including procurement of renewable integration resources. Instead, Section 454.51 grants the Commission the authority to: 1) order the *IOUs* to procure resources identified in the Commission's preferred system portfolio;[41] and 2) authorize the IOUs to impose NBCs for the cost of "incremental renewable integration resources;"[42] and provides an option, but not a requirement, that CCAs can self-procure these resources as an alternative to paying the renewable integration resource NBC.[43]

The PD's assertion that all resources ordered in IRP are renewable integration resources is an error of law. "Renewable integration" refers to a number of distinct *strategies* for incorporating variable-availability renewable resources into the grid, including changing usage patterns through price signaling, resource curtailment, and the procurement of renewable integration resources.[44] In this IRP process, the Commission has determined that the most efficient renewable integration strategy is *curtailment*, not the procurement of specific renewable integration resources. In D.18-02-018 the Commission stated that "[the] curtailment alternative is lower cost than many of the more expensive renewable integration options for much of the time period analyzed."[45] As such, most of the resources identified in the IRP process, the HCP, or the PSP are not renewable integration resources under Section 454.51.

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40 D.18-02-018 at 26.

41 Section 454.51(a – b)

42 Section 454.51(c)

43 Section 454.51(d)

44 D.18-02-018 at 40. See also CAISO, *Discussion and Scoping Paper on Renewable Integration Phase 2* (April 5, 2010) at 3, available at: http://www.caiso.com/ Documents/DiscussionandScopingPaper-RenewableIntegrationMarketandProductReviewPhase2.pd

45 D.18-02-018 at 40. *See also* Administrative Law Judge's Ruling Seeking Comment on Preferred System Portfolio And Transmission Planning Process Recommendations (January 11, 2019), Attachment A at 57.

More broadly, the PD's position that all resources identified in its IRP portfolio are renewable integration resources is an unsupportable interpretation of statute. If the Legislature had intended Section 454.51 to apply to all resources ordered through IRP, it would have clearly worded the section to apply to "all resources" rather than limiting the section to the narrowly defined technical term "renewable integration resources."[46] In addition, the PD's interpretation of Section 454.51, which would effectively allow the Commission to direct all CCA long-term resource procurement, is incompatible with the State's policy of encouraging local energy choice through Community Choice Aggregation[47] and the Commission's recognition of the need to respect the role of individual CCA governing boards to direct an individual CCA's procurement.[48]

V. ANY ATTEMPTS TO ADDRESS RESOURCE SHUFFLING SHOULD BE BASED ON REAL WORLD DATA

The PD asserts that there is a need to address concerns regarding resource shuffling.[49] These concerns, however, are entirely speculative and not based on, or supported by, any record evidence of resource shuffling actually happening in the real world. Indeed, Energy Division staff specifically identified the need to evaluate whether or not resource shuffling occurs as an issue to be resolved in the 2019-20 process.[50] Absent such an analysis, it is premature to conclude without evidence that such resource shuffling is occurring.

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46 *See California Teachers Assn. v. Governing Bd. of Rialto Unified Sch. Dist*. (1997) 14 Cal. 4th 627, 633; *Jones v. Lodge at Torrey Pines P'ship* (2008) 42 Cal. 4th 1158, 1166; *Moore v. California State Bd. Of Accountancy* (1992) 2 Cal. 4th 999, 1031.

47 *See* AB 117.

48 D.18-02-018 at 26.

49 PD at 90, 130.

50 *See* Energy Division Staff presentation "Proposed Preferred System Portfolio for IRP 2017-18: System Analysis and Production Cost Modeling Results" January 7, 2019, at 9, http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Attachment%20A_Proposed%20Preferred%20System%20Portfolio%20for%20IRP%202018_final.pdf

CalCCA's members are is committed to reducing carbon emissions. In light of this commitment, the CCAs have an interest in knowing if any their imported renewable energy purchases result in secondary GHG emissions. Such information would be very helpful in informing CCA procurement decisions. However, any effort to assign a GHG emissions value to imported power should be based on actual, confirmed data of real-world resource shuffling, and should take into account the strong evidence presented in this proceeding that Pacific Northwest hydroelectric imports do not result in resource shuffling or secondary emissions.[51]

VI. CONCLUSION

CalCCA thanks the Commission for its consideration of these comments, and respectfully requests that the Commission adopt the modifications to the PD's findings, conclusions, and ordering paragraphs set forth in Appendix A to these comments, as well as the changes to the discussion section needed for consistency with these modifications.

Dated: April 8, 2019

Respectfully submitted,

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51 See, e.g., *Response of Public Utility District No.2 of Grant County WA to Stakeholder Comments on Load Serving Entities Integrated Resource Plans* (September 26, 2018) at 4.

APPENDIX A: APPENDIX OF PROPOSED MODIFICATIONS
(Modifications to existing language are shown as strike outs for deletions and are underlined and boldfaced for additions.)

MODIFICATIONS TO FINDINGS OF FACT:

Modify Finding of Fact 13 as Follows:

The Commission's primary responsibility, in implementing the provisions of Public Utilities Code Sections 454.51 and 454.52, is to ~~ensure~~ **develop** an electric resource portfolio, for the aggregated LSEs within its purview, that meets the state's GHG emissions, reliability, and cost requirements, as well as other state goals.

Replace Finding of Fact 16 as Follows:

~~All of the LSEs collectively showed a deficiency in the area of reliability and renewable integration resources necessary to achieve the 2030 reliability needs of the system~~.

The both the hybrid conforming portfolio and the reference system portfolio adopt curtailment rather than the procurement of renewable integration resources as the most efficient renewable integration strategy. The resources identified in the preferred system plan are not renewable integration resources.

Eliminate Finding of Fact 35:

~~The Commission has the authority to order long-term procurement of renewable integration resources by CCAs, provided in Section 454.51(d) of the Public Utilities Code.~~

New Finding of Fact:

Reliability resources paid for by a CCA customers through non-bypassable charges should be taken into account when assessing the CCA's contribution to reliablity requirements.

New Finding of Fact:

In the next IRP cycle the Commission should develop a mechanism for incorporating more accurate local information into its modeling inputs and assumptions, including information from LSEs' internal planning processes, when such information is available.

New Finding of Fact:

CCAs have demonstrated the willingness and ability to procure their share of resources needed to achieve SB 350s goals.

New Finding of Fact:

There is no need for new IRP resources until 2026.

New Finding of Fact:

CCA procurement requires a significantly shorter lead time than IOU procurement.

New Finding of Fact:

With each iteration of the IRP process, the Commission should work collaboratively with LSEs to develop more actionable portfolio that includes more specific information regarding the optimal resources needed.

New Finding of Fact:

It is reasonable for the Commission to defer concrete decisions regarding IOU resource procurement to the 2019-2020 IRP cycle.

New Finding of Fact:

In future IRP cycles, the Commission should develop an IRP process that incorporates more accurate local data from individual LSEs when available.

MODIFICATIONS TO CONCLUSIONS OF LAW:

Eliminate Conclusion of Law 18:

~~The Commission should consider exercising its authority to require long-term commitments to renewable integration resources by CCAs in a new "procurement track" of this IRP proceeding.~~

Replace Conclusion of Law 19:

~~The Commission should focus a procurement track of the IRP proceeding on the following types of resources: diverse renewable resources in the near term at levels sufficient to reach the 2030 optimized portfolio, in coordination with the RPS program; near-term resources with load following and hourly intra-hour renewable integration capabilities; existing natural gas resources; and long-duration (8-hour) storage resources.~~

The evidentiary record for this proceeding does not establish a need to consider ordering IOU procurement at this time.

New Conclusion of Law:

In light of CCA Programs' intent and ability to procure the resources needed to achieve SB 350's goals, the Commission should focus on a collaborative approach that provides CCAs with adequate information to inform procurement.

New Conclusion of Law:

The Commission should ensure that its IRP process enables it to fulfill its statewide planning function while also respecting the separate authority of CCA governing boards over procurement decisions (outside of RPS), contract terms of conditions, and rates.

MODIFICATIONS TO ORDERING PARAGRAPHS:

Eliminate Ordering Paragraph 11:

~~The Commission hereby institutes a procurement track, alongside the planning activities in this proceeding, in order to evaluate the need for the following types of resources: diverse renewable resources in the near term at levels sufficient to reach the 2030 optimized portfolio, in coordination with the RPS program; near-term resources with load following and hourly or intra-hour renewable integration capabilities; existing natural gas resources; and long-duration (eight hour) storage resources.~~

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	))))))	Rulemaking 16-02-007 (Filed February 11, 2016)

REPLY COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE PROPOSED DECISION

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April 15, 2019

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The California Community Choice Association

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	))))))	Rulemaking 16-02-007 (Filed February 11, 2016)

REPLY COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE PROPOSED DECISION

In accordance with Rule 14.3(d) of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the California Community Choice Association ("CalCCA") respectfully submits the following reply comments on the *Proposed Decision of ALJ Fitch Adopting Preferred System Portfolio and Plan For 2017-2018 Integrated Resource Plan Cycle* ("Proposed Decision" or "PD").

I. CCAS ARE POSITIONED TO QUICKLY PROCURE NEEDED RESOURCES

Community Choice Aggregators ("CCA"), which will be responsible for approximately 90% of new procurement between now and 2030, are already engaging in large-scale procurement that conclusively demonstrates not only their *capacity* to procure the needed resources, but also their ability to procure new resources *quickly*.[1] A small handful of parties submitted comments questioning CCAs' ability to procure needed resources, but notably none of these parties provided valid justification for this assertion.[2] In addition, a small number of parties asserted an immediate need for the Commission to consider procurement because of "long lead times" required for renewable procurement. Both positions are in error. As demonstrated in Appendix A to these comments CCAs are already engaged in large-scale renewable resource procurement under long-term contracts, with over 410 MW already operational, and another 1,263 MW of new generation and 95 MW of new storage resources contracted to come online in the 2019-2021 timeframe. Including open requests for offers

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1 CalCCA Opening Comments at 3-6. *See also* Appendix A.
2 See NDRC/FOE/CCUE Opening Comments at 9; SDG&E Opening Comments at 12; CalWEA Opening Comments at 3.

("RFO") from EBCE and CPA, a subset of just 8 of California's *CCAs are in the process of procuring between 2,263 and 2,563 MW of renewables that will come online in the 2019-2022 timeframe*. Appendix A further establishes that CCAs are capable of procuring new renewables rapidly: none of the 9 currently operational CCA projects listed in Appendix A took more than 3 years from the issuance of a RFO to reach operational status.

Particularly troubling is CalWEA's claim that CCAs lack the creditworthiness to engage in large scale procurement.[3] Not only have CCAs proven this false through the large scale procurement described above, but as public agencies CCAs have a variety of funding mechanisms available. MCE has an investment-grade credit rating from Moody's, while PCE, SVCE, and MBCP have successfully procured over 400 MW of capacity under long-term contracts. CPA, a newly formed CCA, has already secured funding and is in the process of procuring 400-600 MW of new renewable resources.[4]

In light of the CCAs' ability to quickly procure needed resources, SDG&E's proposal that the Commission expand the definition of "renewable integration resources" for the explicit purpose of expanding the Commission's jurisdiction over CCA procurement[5] is both unnecessary and in error, as such a redefinition would contradict the legislature's clear intent in limiting the Public Utilities Code Section 454.51[6] process to "renewable integration resources" rather than "all renewable resources" or "all resources."

Similarly, a number of parties err in supporting the PD's conclusion that cost should be "co-equal" factor to be weighed in evaluating the Commission's statewide portfolio.[7] Section 454.51 directs the Commission to identify a reliable portfolio that achieves greenhouse gas ("GHG") reductions but does not mention cost minimization. While cost minimization is an important goal, the Commission should not prioritize cost over other equally important goals, including preserving local choice and respecting CCAs' authority to procure resources and set rates based on their own independent judgement regarding cost reasonableness.

II. THE PROCUREMENT TRACK SHOULD FOCUS ON REFINING THE IRP PROCESS AND IDENTIFYING THE BEST RENEWABLE RESOURCES TO DISPLACE FOSSIL GENERATION

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3 CalWEA Opening Comments at 3.
4 *See* Appendix A.
5 SDG&E Opening Comments at 10.
6 All further citations to statute are to the California Public Utilities Code unless otherwise noted.
7 See, e.g., PG&E Opening Comments at 3.

CalCCA agrees with SDG&E and CAISO that it would be neither reasonable nor prudent for the Commission to open a track to consider ordering or authorizing concrete LSE procurement at this time, especially given the PSP's deficiencies, discussed below.[8] A number of parties commented in favor of the PD's proposal to open a broad procurement track to consider ordering or authorizing procurement of reliability and renewable integration resources.[9] These parties are in error. Instead, as detailed in CalCCA's opening comments, the IRP process should focus first on improving the modeling results to provide LSEs with more accurate and actionable information to inform their procurement of optimal resources.[10]

In particular, CalCCA strongly agrees with CEERT that achieving SB 350s goals will require phasing out gas generation and increasing the state's reliance on renewable resources for capacity and reliability services,[11] and with CEJA/SC that the primary focus of the procurement track should be *identifying the optimal new renewable resources to enable the phasing out of natural gas generators*.[12] This is especially true in light of the approximately 2100 MW of excess natural gas generation identified by CAISO in its PLEXOS model and the 2800 MW identified by Energy Division in the SERVM model. The primary purpose of the procurement track should be to: 1) identify gas generators that can be most easily phased out, prioritizing inefficient, high-emissions, and disadvantaged community-located generators; and 2) identify the optimal renewable resources, including resource attributes and locations, to replace the identified gas generators. Such an approach would not jeopardize system reliability because renewable resources deployed by LSEs would be matched to the need identified in IRP to meet reliability needs. As noted by UCS/NRDC, the PD's concerns regarding potential gas reliability resource shortfalls should be addressed by the expansion of RA requirements to 3 years.[13]

III. THE COMMISSION SHOULD NOT REACH CONCLUSIONS OR CONSIDER PROCUREMENT BASED ON THE PSP

In light of the significant errors and deficiencies underlying the PD's rejection of the Hybrid Conforming Portfolio ("HCP") in favor of its recommended Preferred System Portfolio ("PSP"), the Commission should not reach conclusions regarding the adequacy of LSEs' planned procurement or consider actual procurement based on the PSP. Although a number of parties

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8 SDG&E Opening Comments at 4, 9; CAISO Opening Comments at 4.

9 *See, e.g.,* SCE Opening Comments at 3; TURN Opening Comments at 2; CLECA Opening Comments at 4; CalWEA Opening Comments at 3; and AWEA CA Caucus Opening Comments at 2.

10 CalCCA Opening Comments at 2, 11.

11 CEERT Opening Comments at 5.

12 CEJA/SC Opening Comments at 2, 5.

support adoption of the PSP, this support is based almost exclusively on either: 1) unexamined reliance on the PD's conclusion that only the PSP is reliable, least-cost, and meets GHG reduction goals;[14] or 2) the fact that the PSP favors their preferred resources.[15] These parties err in ignoring the PSP's significant errors and deficiencies.

Parties that support the PSP err in ignoring the PSP's *reliability deficiency*. Although SB 350 requires that the Commission adopt a *reliable* portfolio,[16] as both CAISO and PG&E have noted, *the Proposed PSP was not adequately vetted to establish that it would result in a reliable system.*[17] PG&E correctly concludes that without a record that includes reliability modeling of the PSP it is not possible to determine whether the PSP is reliable.[18] No such reliability modeling has occurred: the PD acknowledges that the Commission did not conduct any production cost modeling of the Proposed PSP, and can only "infer" that it is reliable;[19] and as CAISO notes, Commission's late publication of the detailed PSP prevented parties from independently assessing the PSP's reliability.[20]

Parties that support the PSP err in ignoring the PSP's failure to meet the *Commission's GHG target*. Based on SCE's PLEXOS modeling, the PD claims that the PSP would result in lower GHG emissions than the HCP.[21] This claim is highly problematic: the PD rejects the HCP based on its GHG emissions results in SERVM modeling, while adopting the Proposed PSP based primarily on GHG emissions results from SCE's PLEXOS modeling (the Proposed PSP was not modeled in SERVM).[22] An "apples to apples" comparison was never done, but comparison of PLEXOS models, albeit with different assumptions by different institutions, only shows a negligible difference between the two portfolios.[23] If the Commission is going reject the HCP based on the SERVM model results (rather than the range of CAISO PLEXOS results), it

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13 UCS/NRDC Opening Comments at 3.

14 See, e.g., CalPA Opening Comments at 1-2; CEJA/SC Opening Comments at 1-2. Gridliance West Opening Comments at 1-2; SDG&E Opening Comments at 4.

15 *See*, CESA Opening Comments at 2-3; IID Opening Comments at 2.

16 Pub. Util. Code Section 454.52(a)(1)(E).

17 CAISO Opening Comments at 3-4; PG&E Opening Comments at 8.

18 PG&E Opening Comments at 8.

19 PD at 107.

20 CAISO Opening Comments at 4.

21 PD at 105.

22 PD at 105-113.

23 The PSP results in 33.5 MMT in SCE's PLEXOS with gas retirements or 34.2 without retirements, while the HCP results 35.09 MMT in CAISO's PLEXOS model without retirements and better import assumptions, a difference of 2.6%, both slightly over the 34 MMT target for the CAISO areas.

should require that the PSP to first be modeled in SERVM also, or alternatively recognize that both portfolios approximately meet the Commission's GHG targets when modeled in PLEXOS.[24] When judged on an even playing field with the HCP, it appears both portfolios miss the state's GHG targets by comparable degrees, but neither by more than a marginal amount.

Parties that support the PSP err in ignoring overwhelming evidence that the PSP's reliance on outdated inputs and assumptions from the 2017 IEPR has led to highly inaccurate results in this initial trial run of the IRP process. In particular, POC demonstrated that the PSP's price assumptions for solar and battery storage resources are *extremely inaccurate*, and significantly overestimate the price of these resources in 2030.[25] These inaccuracies call into question the entire PSP portfolio that was developed using these assumptions.

Parties that support the PSP err in ignoring the procedural and due process deficiencies that underlie its adoption.[26] As CAISO notes, parties weren't provided with details of the Proposed PSP until April 2019,[27] meaning that parties had no meaningful opportunity to interpedently assess or provide input on the PSP. In addition, as noted by EBCE/PCE, the PD fails to satisfy the requirements of D.18-02-018 by: 1) relying on computer models that have not been vetted; 2) using inconsistent assumptions; and 3) using RESOLVE instead of the required SERVM model to develop the PSP.[28]

IV. CONCLUSION

CalCCA thanks the Commission for its consideration of these reply comments.

Dated: April 15, 2019

Respectfully submitted,

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For: The California Community Choice Association

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24 CEERT Opening Comments at 3.
25 POC Opening Comments at 2-5.
26 *See*, CalCCA Opening Comments at 9-10.
27 CAISO Opening Comments at 3.
28 EBCE/PCE Opening Comments at 13-15. In addition, CalCCA notes that the PD relies on significant amounts of material that are not part of this proceeding's record.

Appendix A To CalCCA PD Reply Comments:
Table of CCA Renewable Projects (10MW +)

CCA	Project Name	Size (MW)	Tech.	Contract Term (Years)	RFO Date (Mo/Yr)	Contract Date (Mo/Yr)	Operational Date (Mo/Yr)*	Time – RFO to Operation	Time – Contract to Operation
MCE	Solar One	10.5 MW	Solar	20	6 / 2016	5 / 2017	12 / 2017	1 yr., 6 mo.	7 mo.
MCE	Antelope Expansion 2	105 MW	Solar	20	12 / 2015	11 / 2016	12 / 2018	3 yr.	2 yr., 1 mo.
MCE	Great Valley 1	100 MW	Solar	15	12 / 2015	9 / 2016	4 / 2018	2 yr. 5 mo.	1 yr. 7 mo.
MCE	Voyager II	42 MW	Wind	12	12 / 2015	12 / 2016	12 / 2018	3 yr.	2 yr.
MCE	Mustang 4	30 MW	Solar	15	N/A	10 / 2014	Operation prior to contract.	N/A	N/A
MCE	Little Bear 1	40 MW	Solar	20	12 / 2015	9 / 2016	*12 / 2020*	TBD	TBD
MCE	Little Bear 3	20 MW	Solar	20	12 / 2015	9 / 2016	*12 / 2020*	TBD	TBD
MCE	Little Bear 4	50 MW	Solar	20	12 / 2015	9 / 2016	*12 / 2020*	TBD	TBD
MCE	Little Bear 5	50 MW	Solar	20	12 / 2015	9 / 2016	*12 / 2020*	TBD	TBD
MCE	Strauss Wind	98.83 MW	Wind	15	1 / 2018	6 / 2018	*TBD (2020)*	TBD	TBD
MCE	Desert Harvest	80 MW	Solar	20	12 / 2015	11 / 2016	*12 / 2020*	TBD	TBD
SVCE + MBCP	BigBeau Solar	128 MW (Solar) + 40 MW (4-hour storage)	Solar + Storage	20	9 / 2017	10 / 2018	*12 / 2021*	TBD	TBD
SVCE + MBCP	RE Slate	150 MW (Solar) + 45 MW (4-hour storage)	Solar + Storage	15	9 / 2017	10 / 2018	*6 / 2021*	TBD	TBD
SVCE + MBCP	Duran Mesa Wind	200 MW	Wind	15	9 / 2017	7 / 2018	*12 / 2021*	TBD	TBD
SCP	RE Mustang	30 MW	Solar	20	3 / 2014	6 / 2014	8 / 2016	2 yr. 5 mo.	2 yr. 2 mo.
SCP	RE Mustang 3	40 MW	Solar	20	3 / 2014	10 / 2014	7 / 2016	2 yr., 4 mo.	1 yr. 9 mo.
SCP	Golden Hills North	46 MW	Wind	20	N/A	7 / 2016	11 / 2017	N/A	1 yr. 4 mo.
SCP	Sand Hill C	80 MW	Wind	20	1 / 2018	7 / 2018	*1 / 2021*	TBD	TBD
SCP	Proxima Solar	50 MW	Solar	20	1 / 2018	9 / 2018	*6 / 2023*	TBD	TBD
LCE	Western Antelope Dry Ranch	10 MW	Solar	20	6 / 2015	8 / 2015	11 / 2016	1 yr., 5 mo.	1 yr., 3 mo.
PCE	Wright Solar Park	200 MW	Solar	25	11 / 2016	1 / 2017	*11 / 2019*	TBD	TBD
PCE	Mustang II Whirlaway	100 MW	Solar	15	11 / 2016	8 / 2017	*12 / 2020*	TBD	TBD
Cleanpower	San Pablo	100 MW	Solar	22	6 / 2017	6 / 2018	*7 / 2019*	TBD	TBD

SF	Raceway								
Cleanpower SF	Voyager IV	47 MW	Wind	15	9 / 2017	6 / 2018	*11 / 2020*	TBD	TBD
CPA	2018 Clean Energy RFO (In process)	400-600 MW	Solar; Solar + Storage; Standalone Storage	15-20 years	10 / 2018	*6 / 2019*	*2020-2022*	TBD	TBD
EBCE	2018 California Renewable RFP (In process)	600-700 MW	Solar; Wind; Solar + Storage	15-20 years	6 / 2018	*6 / 2019*	*2020-2022*	TBD	TBD

*Contracted delivery dates for plants that are not yet operational are identified in *italics*.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002 (Filed July 10, 2014)

OPENING COMMENTS OF PENINSULA CLEAN ENERGY, MARIN CLEAN ENERGY, EAST BAY COMMUNITY ENERGY, LANCASTER CHOICE ENERGY, AND CLEAN POWER ALLIANCE OF SOUTHERN CALIFORNIA ON DRAFT RESOLUTION E-4999 APPROVING WITH MODIFICATION TARIFFS TO IMPLEMENT THE DISADVANTAGED COMMUNITIES GREEN TARIFF AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS PURSUANT TO DECISION 18-06-027

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May 20, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002 (Filed July 10, 2014)

OPENING COMMENTS OF PENINSULA CLEAN ENERGY, MARIN CLEAN ENERGY, EAST BAY COMMUNITY ENERGY, LANCASTER CHOICE ENERGY, AND CLEAN POWER ALLIANCE OF SOUTHERN CALIFORNIA

I. Introduction

On behalf of Peninsula Clean Energy ("PCE"), Marin Clean Energy ("MCE"), East Bay Community Energy ("EBCE"), Lancaster Choice Energy ("LCE"), and Clean Power Alliance of Southern California ("CPA") (collectively, "Joint CCAs"), PCE submits these comments on the California Public Utilities Commission's ("Commission") Draft Resolution E-4999 ("Draft Resolution"), issued April 29, 2019, and proposed for adoption by the Commission on May 30, 2019.[1]

The Draft Resolution approves, with modifications, Pacific Gas and Electric Company's ("PG&E") Advice Letter ("AL") 5362-E/E-A, Southern California Edison Company's ("SCE") AL 3851-E/E-A, and San Diego Gas & Electric Company's ("SDG&E") AL 3262-E/E-A/E-B to

[1] In accordance with Rule 1.8(d), MCE, EBCE, LCE, and CPA have authorized the undersigned counsel to submit these comments on their behalf.

create Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CSGT") rates, in compliance with Decision ("D.") 18-06-027. In approving these ALs, the Draft Resolution adopts PG&E's proposed methodology for allocating capacity under the DAC-GT and CSGT programs to CCAs, provides for the trading of capacity among CCAs, establishes cost caps, requires participating CCAs to file Advice Letters on or before January 1, 2021, and foregoes, for the time being, a stakeholder workshop.

The Joint CCAs appreciate the opportunity to work with the Commission and the investor-owned utilities ("IOUs") to improve access to renewable energy generation for residential customers in disadvantaged communities ("DACs"). The Joint CCAs suggest in our comments below a few points of clarification and revision in the Draft Resolution that would help achieve that central goal.

II. Comments

A. The Joint CCAs support the Draft Resolution's capacity-trading scheme, with clarifications and modifications.

The Joint CCAs appreciate that the Draft Resolution recognizes that, under the proposed program capacity allocations, some CCAs have "small capacity allocations."[2] Accordingly, the Draft Resolution "will allow CCAs that serve customers that are served by the same IOU to share and/or trade program capacity."[3] The Draft Resolution explains:

> Specifically, for DAC-GT, two or more CCAs may elect to pool some or all of their capacity allocations to offer a shared RFO for projects to serve their DAC customers. In addition, for DAC-GT or CSGT, a CCA that does not wish to launch its own program may designate another CCA who serves customers that are also served by the same IOU to receive its program capacity allocation. If a CCA elects to utilize any of these options, it must detail the proposal in its Tier 3

[2] Draft Resolution E-4999, at 16.

[3] Draft Resolution E-4999, at 16.

AL filing and the filing must be affirmed in writing through comments on the AL filing by any CCA whose program capacity is implicated in the proposal.[4]

The Joint CCAs generally applaud the Commission's proposal to allow CCAs more flexibility in their implementation of the DAC-GT and CS-GT programs by offering the opportunity to share and/or trade program capacity. However, we have several concerns and clarifying questions regarding this capacity-trading scheme.

First, the Draft Resolution includes a "clawback" provision whereby capacity allocated to CCAs "shall revert back to the IOUs if the CCAs do not file Tier 3 ALs detailing their plans to implement DAC-GT and CSGT programs, and stating the capacity they will procure for each program, by January 1, 2021."[5] However, a CCA may decide to trade its capacity to another CCA under the capacity-trading scheme and as a non-participating CCA would not be required to file a Tier 3 AL. For this reason, the statement above should be revised to say that the capacity allocated to CCAs "shall revert back to the IOUs if the CCAs do not file Tier 3 ALs detailing their plans to implement DAC-GT and CSGT programs, and stating the capacity they will procure for each program *(including any shared or traded capacity from another CCA)*, by January 1, 2021" (new language in italics). This revised statement will make clear that, once a CCA claims capacity allocated to it or another CCA in a Tier 3 AL, that capacity is not subject to reversion to an IOU under the clawback provision. Furthermore, the Energy Division should ensure that any unused capacity not claimed in a Tier 3 AL should revert first to any participating CCAs, instead of to the IOUs. This approach is more consistent with the intent behind the CCA allocations and the capacity-trading scheme. Finally, the Joint CCAs

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[4] Draft Resolution E-4999, at 16.

[5] Draft Resolution E-4999, at 16.

recommend that, should the IOUs be unable to fulfill the requirements of the DAC-GT and/or CSGT programs, remaining program capacity should be made available to participating CCAs.

Second, the Joint CCAs believe more detail is required concerning how the capacity-trading scheme would work in practice. For example, the Draft Resolution appears to state that capacity pooling is available only for the DAC-GT program. We do not believe this restriction makes sense, as it could, among other things, serve to preclude two or more CCAs with adjacent service territories from building a joint CS-GT project in neighboring DACs. Hence, we encourage the Commission to clarify that capacity pooling or sharing is also allowed under the CS-GT program.

Finally, the Joint CCAs request confirmation from the Commission of their understanding that a CCA that does not wish to launch its own program may designate several other CCAs (in the same IOU territory) to receive its program capacity allocation (instead of just one receiving CCA). The capacity allocations traded to each receiving CCA will be detailed in the Tier 3 AL filing of each receiving CCA and affirmed in writing through comments on the AL by the CCA whose program capacity is designated in the proposal.

B. The Joint CCAs propose to allow for Petitions to Modify to request additional program capacity under the CS-GT program by Program Administrator.

D.18-06-027 allows for a Petition to Modify ("PTM") if it appears that the CS-GT program cap may be reached.[6] The Joint CCAs request the Commission to consider applying this requirement on a Program Administrator level instead of at the IOU service territory or statewide level. There could be many reasons leading to program implementation and adoption that is faster in certain Program Administrators' service territories compared to others. These

[6] *See* D.18-06-027, at 65.

reasons may range from different levels of customer interest to implementation restraints.[7] Therefore, the Joint CCAs propose that each Program Administrator should be able to file a PTM with the Commission once the CS-GT program cap in its service territory has been reached. This allowance would apply equally to all Program Administrators, i.e., IOUs *and* CCAs.

C. Additional clarity and direction is needed concerning program cost caps.

D.18-06-027 required a cost cap for only the CS-GT program, but the Draft Resolution establishes a cost cap for the DAC-GT program, too.[8] Specifically, the Draft Resolution establishes the same 200% cap applicable to Environmental Justice ("EJ") community projects under the Green Tariff Shared Renewables ("GTSR") program.[9]

The Joint CCAs would like clarity on whether the new DAC-GT cost cap will apply to IOUs and CCAs (or just IOUs). The cost cap contemplated in the Draft Resolution was requested by only the IOUs and therefore should not apply to CCAs. That is, while we respect the IOUs' decision to impose a cost cap on their administration of the DAC-GT program, CCAs did not request the cost cap and it therefore should not broadly apply to CCAs.

If the Commission's decision is to establish the same cost cap for CCAs and IOUs (i.e., a cost cap for the entire DAC-GT program, as well as the CS-GT program), we submit that the proposed cap—the 200% cap applicable to GTSR EJ community projects—is set too low to ensure program feasibility, for at least two reasons. First, the size of solar projects developed

[7] For example, both SCE and SDG&E have indicated in their Implementation Advice Letters that, due to IT system upgrade challenges, automated customer billing will be delayed until 2021.

[8] *See* D.18-06-027, at 84; Draft Resolution E-4999, at 35, 54 (Ordering Paragraph 1). The Draft Resolution explains that "[t]he Decision did not discuss a cost containment mechanism for DAC-GT, but both PG&E and SCE include one in their ALs." Draft Resolution E-4999, at 35.

[9] Draft Resolution E-4999, at 35. Specifically, the Draft Resolution adopts PG&E's cap that "'bid pricing must be at or below the higher of 200% of the maximum executed contract price in either the previous PV/RAM as-available peaking category or the Green Tariff program.'" *Id.* (quoting PG&E AL 5362-E, at 10).

under the programs could be much smaller than projects developed under both the Renewable Auction Mechanism ("RAM") as-available peaking category or GTSR programs, especially in CCA territories with limited program capacity, and correspondingly more expensive. Second, CCAs (and possibly IOUs) may choose to install projects in urban areas, which likely are more expensive than the typical GTSR project, which thus far are all located in the Central Valley.[10] A cost cap based on a more comparable measure, which the Joint CCAs would be amenable to identifying, might be a better fit for the DAC-GT and CS-GT programs.

Finally, the Draft Resolution does not address the fact that CCAs do not have access to the information underlying the IOUs' cost cap as the IOUs hold this information confidentially. CCAs cannot adequately assess program feasibility and proceed with program design and development without this information. Accordingly, we request that the Commission order the IOUs to provide the information underlying their cost cap, pursuant to a non-disclosure agreement, within 30 days of the Commission's approval of the Draft Resolution.

D. Miscellaneous issues

The Joint CCAs would appreciate additional clarity regarding a few other issues. First, we read D.18-06-027 and the Draft Resolution to allow Program Administrators the flexibility to offer either one or both of the DAC community solar programs to their customers. Due to the smaller size of CCAs and their related staffing and resource constraints, it may be challenging for CCAs to offer both programs, especially if the allocated MW capacity is small. The increased administrative burden, time, and cost associated with offering both programs may not justify the

[10] *See* https://www.pge.com/en_US/residential/solar-and-vehicles/options/solar/solar-choice/energy-sources.page.

added benefit to customers and the additional ratepayer costs. We would appreciate confirmation from the Commission of our understanding.

Second, it is currently unclear if solar projects procured by a CCA under both programs would have to be located in a DAC within the respective CCA's service territory or in a DAC within the IOU's service territory in which the CCA is located. Clarification on this point is particularly important for the DAC-GT program, as this program does not have locational requirements like the CS-GT program. We would appreciate guidance from the Commission on this topic.

E. Stakeholder workshops may be necessary in the future.

The Joint CCAs are disappointed in the decision to forego a stakeholder workshop,[11] as we believe it would have been the most efficient way to identify and address CCA-related concerns with the IOUs' ALs. However, as the Commission suggests, the Joint CCAs will work with the IOUs on implementation questions as they arise after the approval of the Draft Resolution. It is our understanding that the Commission intends to hold a workshop after the Draft Resolution is approved to coordinate implementation issues between the IOUs and CCAs. We look forward to participating in this workshop and would like to highlight some of the implementation questions that we believe merit workshop discussion:

1. Cost cap issues, including but not limited to the appropriate setting of the cost cap for all Program Administrators, as well as the sharing of confidential cost cap information.
2. Interaction by CCAs in the IOUs' respective Energy Resource and Recovery Account ("ERRA") Forecast and Review process, including timing of budget

[11] Draft Resolution E-4999, at 17.

approval for the initial year of program implementation and processes and general ERRA forecasting procedures (a process currently implemented only by IOUs).

3. Customer billing and cost tracking, including identifying the most cost-efficient and streamlined processes for these tasks.

III. Conclusion

The Joint CCAs appreciate this opportunity to comment on the Draft Resolution. We look forward to evaluating and, as appropriate, implementing the DAC-GT and CS-GT programs to increase access to renewable energy by residential customers in disadvantaged communities.

Dated: May 20, 2019

Respectfully submitted,

/s/ Matthew J. Sanders

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May 8, 2019

Via E-Mail

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Re: Joint CCA Parties' Informal Comments on the Revised Consumer Information Packet

Dear Ms. Fleisher:

Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), Peninsula Clean Energy Authority ("PCE"), Redwood Coast Energy Authority ("RCEA"), Monterey Bay Community Power ("MBCP"), Pioneer Community Energy ("Pioneer") and the California Choice Energy Authority ("CCEA") ("Joint CCA Parties") provide these informal comments on the Revised Solar Information Packet ("Revised Packet") and Request for Comment issued by the California Public Utilities Commission's ("Commission") Energy Division staff ("Staff") on April 26, 2019.[1] The Joint CCA Parties appreciate this opportunity to provide feedback on the Revised Packet and focus their comments on the content of the Revised Packet. The Joint CCA Parties further appreciate the steps Staff has taken to improve the Solar Information Packet and believe that the changes included in this Revised Packet make it easier for customers to understand their rights as well as the process for connecting a rooftop solar system.

The Joint CCAs are, however, concerned that the Revised Packet may be confusing to customers of Community Choice Aggregators ("CCAs"), and potentially misleading. The Revised Packet references "PG&E, SCE, or SDG&E customers" or "customers in PG&E, SCE, or SDG&E territories" in various sections.[2] However, it is not clear whether these references apply to joint Investor-Owned Utility ("IOU") and CCA customers or to IOU bundled customers. For example, the Revised Packet notes "Customers in PG&E, SCE, and SDG&E territories are guaranteed NEM for 20 years from the time their solar system starts operating."[3] This applies to both bundled and unbundled customers under the Commission's *Decision Adopting Successor to*

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[1] The Joint CCA Parties represent various Community Choice Aggregation programs in California. Approximately 25 percent of the load of Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDG&E") is served by CCA programs, with a significantly higher percentage of load in PG&E's service area.

[2] *See* Revised Packet at 5, 9, 14.

[3] Revised Packet at 14.

Net Energy Metering Tariff.[4] However, other portions of the Revised Packet focus on IOU-centered low-income programs directed to "PG&E, SCE, or SDG&E customers" that exclude CCA customers.[5] Customers contemplating going solar may not easily understand whether they are IOU customers or whether they qualify as customers in an IOU territory.

The Commission *Decision Adopting Net Energy Metering Consumer Protection Measures Including Solar Information Packet* states that "the information packet should be posted on the Commission's website, as well as websites of the CSLB, utilities/community choice aggregators, CALSSA, solar providers, local governments, and CPUC program websites such as the Solar on Multifamily Affordable Housing ("SOMAH") website."[6] Accordingly, the final Solar Information Packet will be made available to customers across California regardless of which load serving entity supplies their electricity. Furthermore, CCA customers connect their solar systems through the IOUs. Therefore, it is important to ensure that CCA customers, as well as bundled IOU customers, are equally able to understand their rights when installing solar. By giving CCAs recognition in the Revised Packet, all customers are provided with more clarity regarding their rights and protections when connecting a solar system.

The Joint CCAs also request that the Revised Packet be modified to ensure competitive neutrality with respect to community solar programs. As it is now, the Revised Packet references the IOUs' respective community solar programs, but does not acknowledge similar programs offered by CCAs: "If you are a PG&E, SCE, or SDG&E customer, you can sign up for a community solar program and receive 50-100% of your electricity from solar projects located across California."[7] The IOUs' community solar programs are largely operated under the Green Tariff Shared Renewables Program established in Senate Bill 43 (2013), and implemented by the Commission through D.15-01-051.[8] The Commission dedicated a significant portion of D.15-01-051 to discuss competitive neutrality between the IOUs and CCAs.[9] Since CCAs also offer community solar programs and other similar programs, the Joint CCAs request that the Revised Packet be revised to ensure competitive neutrality in the recognition of community solar programs. This also applies to the Revised Packet's various references to net-energy metering ("NEM") programs. CCA customers also have the opportunity to enroll in NEM programs offered by their respective CCAs, and the Revised Packet should reflect this fact.

For the reasons stated above Energy Division should implement the redlined changes attached herein to include CCA representation within the Revised Packet.

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[4] *See* D.16-01-044. (CCA and DA customers "will be able to use the NEM successor tariff on the same terms as IOU customers.")

[5] Revised Packet at 9.

[6] D.18-09-044 at 27.

[7] Revised Packet at 5.

[8] Recently, the Commission also adopted D.18-06-027, which authorized the IOUs and CCAs to develop solar distributed generation in disadvantaged communities.

[9] *See* D.15-01-051 at 144-156.

Respectfully,

/s/

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On behalf of the Joint CCA Parties

Copy (via e-mail): Service Lists: R.14-07-002
R.12-11-005

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

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.	Application 14-11-007 (Filed November 18, 2014)
And Related Matters	Application 14-11-009 Application 14-11-010 Application 14-11-011

COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION ISSUING GUIDANCE TO INVESTOR-OWNED UTILITIES FOR CALIFORNIA ALTERNATE RATES FOR ENERGY/ ENERGY SAVINGS ASSISTANCE PROGRAM APPLICATIONS FOR 2021-2026 AND DENYING PETITION FOR MODIFICATION

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May 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.	Application 14-11-007 (Filed November 18, 2014)
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COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION ISSUING GUIDANCE TO INVESTOR-OWNED UTILITIES FOR CALIFORNIA ALTERNATE RATES FOR ENERGY/ ENERGY SAVINGS ASSISTANCE PROGRAM APPLICATIONS FOR 2021-2026 AND DENYING PETITION FOR MODIFICATION

Pursuant to Rule 14.3 of the California Public Utility Commission's ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE")[1] respectfully submits the following comments on the *Proposed Decision Issuing Guidance to Investor-Owned Utilities for California Alternate Rates for Energy/ Energy Savings Assistance Program Applications for 2021-2026 and Denying Petition for Modification* ("Proposed Decision") filed April 30, 2019.

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[1] MCE is California's first operational community choice aggregation ("CCA") program and began providing retail electricity service to customers on May 7, 2010. Today, MCE provides retail electricity generation services to over 470,000 customer accounts within PG&E's service territory. These communities include Marin County and Napa County. It also includes unincorporated Contra Costa County, as well as the cities of Richmond, San Pablo, El Cerrito, Walnut Creek, Lafayette, Concord, Martinez, Oakley, Pinole, Pittsburg and San Ramon and the towns of Danville and Moraga. MCE also serves the city of Benicia in Solano County and MCE recently filed an Implementation Plan with the Commission to certify expansion into unincorporated Solano County.

I. INTRODUCTION

MCE appreciates the Commission's express focus in the Proposed Decision on "deeper energy savings and innovative program design for the multifamily sector"[2] under the Energy Savings Assistance ("ESA") Program for the 2021-2026 program cycle. The Commission authorized MCE in D.16-11-022, as modified by D.17-12-009, to run the Low-Income Families and Tenants ("LIFT") pilot program to serve income-qualified multifamily properties by leveraging general energy efficiency ("EE") programs and low-income energy savings programs.[3] The MCE LIFT pilot program has been offering technical assistance, rebates, and fuel switching opportunities from gas and propane to electric heat pumps to income-qualified multifamily property owners and residents since October 2017.

In the sections below, MCE provides comments on some of the proposals related to the Multifamily Whole Building Program ("MFWB") as described in the Proposed Decision and the *Guidance Document for the Energy Savings Assistance (ESA) and California Alternate Rates for Energy (CARE) Program Budget Applications for Program Years 2021-2026* ("Guidance Document") that is attached to the Proposed Decision.

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[2] Proposed Decision at 8

[3] Decision D.17-12-009, *Decision Resolving Petitions for Modification of Decision 16-11-022*, OP 148 at 506.

II. COMMENTS

A. The Commission Should Align the Concepts of "Program Administrator" and "Third-Party Implementer" for the Multifamily Whole Building Program with Existing Third-Party Program Rules

The Proposed Decision recommends moving to the concept of third-party program design and delivery for the ESA MFWB, consistent with the direction under the general EE programs.[4] MCE supports this proposal to encourage more innovation in MFWB programs. Furthermore, MCE encourages the alignment of ESA MFWB program rules with the ones for the general IOU EE programs to the extent possible to increase consistency between low-income and general EE programs and to reduce program complexities.

While MCE supports the third-party program design and delivery model for the ESA MFWB program, the Proposed Decision should be modified to eliminate some inconsistencies between the approach in the Proposed Decision and Guidance Document regarding the concepts of third-party delivery of the MFWB program and third-party delivery in the general EE programs.

Under the general EE third party programs, the terms "program administrator" ("PA") and "third-party implementer" have very specific meanings. The PA oversees the EE program portfolio and designates much of the program design and delivery to third-party implementers, which are different from traditional implementers because they are primarily responsible for program design.[5]

It is MCE's understanding that it is the intent of the Commission to institute third-party program <u>implementation</u> for the ESA MFWB program, not third-party program <u>administration</u>. This would ensure consistency with the general EE programs. MCE recommends the following

[4] See Proposed Decision at 8 and Guidance Document at 2 and 18
[5] D.16-08-019 at p. 67-69.

modifications to the Proposed Decision and Guidance Document (additions are underlined, deletions are ~~struck out~~):

> "The Commission is specifically interested in a focus on deeper energy savings and innovative program design for the multifamily sector, including third party implementation ~~administration~~ (i.e., third party program design and delivery ~~implementation~~) of a low-income multi-family whole building energy efficiency program. This is consistent with the direction of the general IOU energy efficiency programs."[6]

> "The IOUs should propose alternative program design, including third party implementation ~~administration~~ of the ESA multifamily whole building program, in compliance with statutory budget requirements."[7]

MCE supports the movement to a third-party implementer approach for the MFWB while maintaining consistency with the third-party rules for general EE programs.

B. The Commission Should Avoid Proposing a Single Statewide Implementer for the Multifamily Whole Building Program

The Guidance Document states that "the IOUs are strongly advised to consider a statewide program with a single implementer" for the MFWB program.[8] The Commission should avoid recommending a single, statewide program implementer for the MFWB program as it is generally not appropriate for a downstream program to be implemented statewide. Downstream programs should be integrated and coordinated, and program leveraging has proven to be a successful tool in downstream program implementation in the multifamily context. For example, MCE's LIFT pilot for low-income multifamily properties has been successfully leveraging MCE's general EE Multifamily Energy Savings Program to maximize customer incentives, facilitate customer recruitment and streamline administrative processes. Implementing downstream programs

[6] Proposed Decision at 8
[7] Guidance Document at 2
[8] Guidance Document at 18

statewide risks splintering savings opportunities and increasing program delivery costs. Additionally, downstream programs involve customer touches and local needs that vary and require program tailoring. This is particularly true in the multifamily and low-income context where much of the eligible population can be considered "hard-to-reach." Finally, a single statewide implementer may not have adequate penetration in certain markets which risks segments of the low-income population being underserved.

This point of view is supported by the Commission's own decisions. The CPUC defined "statewide" in Decision 16-08-019 and highlighted that only certain types of EE programs are appropriate for statewide administration:

> "Upstream (at the manufacturer level) and midstream (at the distributor or retailer level, but not the contractor or installer level) interventions are required to be delivered statewide. Some, but not all, downstream (at the customer level) approaches are also appropriate for statewide administration."[9]

That decision also expressly rejected the concept of a statewide implementer, citing concern by parties that one entity may not be able to deliver all aspects of the program and determined that PAs should determine how many implementers are needed for a single program.[10]

For these reasons, MCE opposes the concept of a statewide program with a single implementer for the MFWB program. A preferable approach is for each PA to continue to be responsible for ensuring adequate third-party implementation throughout their low-income populations. Allowing for diversity in program design from implementers will promote innovation which will lead to stronger ESA MFWB programs over time.

[9] Decision 16-08-019, *Decision Providing Guidance for Initial Energy Efficiency Rolling Portfolio Business Plan Filings*, at 111.
[10] D.16-08-016, at 51-52.

III. CONCLUSION

MCE thanks the assigned Administrative Law Judge Kwan MacDonald and Commissioner Rechtschaffen for their thoughtful consideration of these comments.

Respectfully submitted,
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May 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.	Application 14-11-007 (Filed November 18, 2014)
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REPLY COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION ISSUING GUIDANCE TO INVESTOR-OWNED UTILITIES FOR CALIFORNIA ALTERNATE RATES FOR ENERGY/ ENERGY SAVINGS ASSISTANCE PROGRAM APPLICATIONS FOR 2021-2026 AND DENYING PETITION FOR MODIFICATION

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May 28, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.	Application 14-11-007 (Filed November 18, 2014)
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REPLY COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION ISSUING GUIDANCE TO INVESTOR-OWNED UTILITIES FOR CALIFORNIA ALTERNATE RATES FOR ENERGY/ ENERGY SAVINGS ASSISTANCE PROGRAM APPLICATIONS FOR 2021-2026 AND DENYING PETITION FOR MODIFICATION

Pursuant to Rule 14.3 of the California Public Utility Commission's ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE")[1] respectfully submits the following reply comments on the *Proposed Decision Issuing Guidance to Investor-Owned Utilities for California Alternate Rates for Energy/ Energy Savings Assistance Program Applications for 2021-2026 and Denying Petition for Modification* ("Proposed Decision") filed April 30, 2019.

[1] MCE is California's first operational community choice aggregation ("CCA") program and began providing retail electricity service to customers on May 7, 2010. Today, MCE provides retail electricity generation services to over 470,000 customer accounts within PG&E's service territory. These communities include Marin County and Napa County. It also includes unincorporated Contra Costa County, as well as the cities of Richmond, San Pablo, El Cerrito, Walnut Creek, Lafayette, Concord, Martinez, Oakley, Pinole, Pittsburg and San Ramon and the towns of Danville and Moraga. MCE also serves the city of Benicia in Solano County and MCE recently filed an Implementation Plan with the Commission to certify expansion into unincorporated Solano County.

I. REPLY COMMENTS

A. MCE Provides Additional Information About Its Low-Income Family and Tenants Pilot Program in Response to The Greenlining Institute's Opening Comments.

MCE appreciates the comments from The Greenlining Institute on MCE's Low-Income Family and Tenants ("LIFT") pilot.[2] In response to those comments, MCE provides additional details and clarifications on the reporting requirements, status, and proposed future of LIFT. Decision ("D.") 16-11-022, as modified by D.17-12-009 ("the LIFT Decision"), details MCE's reporting requirements for the LIFT pilot. The decision states:

> "We find it reasonable and direct MCE to file monthly progress reports, two interim reports with preliminary findings, report to the LIOB quarterly on its pilot, and submit a final report upon conclusion of the pilot, as proposed. These reports shall be filed with Energy Division."[3]

MCE has been submitting monthly and quarterly progress reports to Energy Division Central Files and the service list for the above-captioned proceeding since LIFT's launch on October 31, 2017. These reports provide updates on program metrics, including budget and expenditures, participating unit and heat pump count, energy savings, energy efficiency ("EE") measures implemented, and households treated. Pursuant to the LIFT Decision, MCE also submitted an interim report on the LIFT pilot to Energy Division Central Files and the above-mentioned service list on April 30, 2019. The interim report provides a more holistic picture of the successes and challenges of the LIFT pilot program to date and describes the status of program metrics established in MCE Advice Letter 23-E-A[4].

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[2] The Greenling Institute's opening comments, section II.f at 7

[3] *Administrative Law Judge's Ruling Providing a Clean Copy of the Modified Red-Lined Version of D.16-11-022* ("Clean Copy of D.16-11-022"), February 2, 2018, at 386

[4] MCE was ordered in D.16-11-022 to provide detailed program metrics which MCE submitted in Advice Letter ("AL") 23-E, *Identification of Metrics to Track Marin Clean Energy's Low-Income Families and Tenants Pilot* on April 6, 2017. This AL was supplemented by AL 23-E-A on July 20, 2017, which provided the updated and final metrics and revisions to the LIFT pilot.

1. MCE provides select findings to inform the ESA Guidance Decision's findings and future program design and development.

A few of the findings and lessons learned from MCE's LIFT interim report are useful to inform future program design and development of multifamily ESA programs and are therefore briefly mentioned here. First and foremost, MCE has found that timelines for implementing energy efficiency measures in the multifamily context are extremely long. For example, the timeline between a property showing interest in participating in a multifamily EE program and finalizing the scope of work can be up to 12 months. It then can take up to another 6 months to install the agreed-upon measures. Factors that contribute to extended timelines are that many stakeholders are involved in the decision-making process, EE upgrades are often coordinated with larger renovation projects, and property owners are often faced with time and resource constraints. Additionally, informed EM&V analyses can only be completed once sufficient time has passed to collect detailed program data, e.g., customer billing data for energy savings and bill impact analysis.

This delay between property interest, project implementation, and availability of empirical results demonstrates that timelines for implementing multifamily EE measures can be extensive. This should be considered when designing and developing future ESA programs. As such, MCE cautions against designing multi-family programs on a shorter timeframe under the ESA 2021-2026 program cycle as La Cooperative Campesina de California proposes in their comments on the Proposed Decision.[5]

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[5] La Cooperative Campesina proposes that the Commission take a probationary approach introducing third-party administration, third-party implementers, and the Multifamily Whole Building Program. They also request the Commission to consider multi-program tracks that are funded for up to two-years for the purpose of collecting data to better inform future core design of ESAP. See comments of La Cooperative Campesina, section B, at 4

A second finding of the LIFT pilot program to date that may be beneficial in informing future program design is the fact that program outreach through Community Based Organizations has not proven to be the optimal outreach strategy for customer recruitment under LIFT. MCE has found that property managers and property owners are a more efficient and effective means to identify program participants because they are in the position to make decisions about EE upgrades for the entire property instead of having to work directly with individual residents to serve each unit.

B. MCE Requests the ESA Guidance Decision Authorize MCE to Extend the LIFT Pilot Via A Tier 2 Advice Letter Through the End of the Current Program Cycle.

In response to The Greenlining Institute's opening comments, MCE also takes this opportunity to provide more clarity on the envisioned future of the LIFT pilot program.[6]

MCE proposed LIFT as a two-year pilot program. The program launched in October 2017 and is scheduled to terminate at the end of October 2019. Due to the aforementioned extended timelines under the LIFT pilot program, MCE would like to continue to offer the program and enroll new customers under the existing LIFT pilot program beyond October 2019 through the end of the current ESA program cycle.[7] As The Greenlining Institute pointed out in its opening comments, the LIFT Decision allowed MCE to seek additional funding for future program years through a Petition for Modification ("PFM").[8] A PFM, however, is not a feasible option in this particular case as the review and approval of a PFM often takes 12 to 18 months.[9] For a two-year

[6] The Greenling Institute's opening comments, section II.f at 7

[7] MCE does not request an extension of the current LIFT pilot program into the future 2021-2026 program cycle. As directed by D.16-11-022, MCE would use the Application process if it elects to extend the LIFT pilot on a more permanent basis into future ESA program cycles.

[8] The Greenling Institute's opening comments, section II.f at 7 and Clean copy of D.16-11-022 at 387.

[9] Clean copy of D.16-11-022 at 234

pilot program, it is impractical if not impossible to propose programmatic changes through PFMs under such a timeline.

For this reason, MCE hereby requests the Commission authorize MCE to propose an extension to the LIFT pilot via a Tier 2 advice letter.

II. CONCLUSION

MCE thanks the assigned Administrative Law Judge Kwan MacDonald and Commissioner Rechtschaffen for their thoughtful consideration of these reply comments.

Respectfully submitted,
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May 28, 2019

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

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety	Investigation 15-08-019 (Filed August 27, 2015)

**MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION**

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June 7, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	Investigation 15-08-019 (Filed August 27, 2015)

MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission's Rules of Practice and Procedure and Public Utilities Code Section 1701.3(h)(2), Marin Clean Energy ("MCE") hereby gives notice of the following *ex parte* communication.[1] The communication was initiated by Commissioner Guzman-Aceves' office, and occurred on June 04, 2019 at approximately 1:30 pm. The communication was held in-person at the California Public Utilities Commission in San Francisco, California. The communication was between Shalini Swaroop, MCE General Counsel; C.C. Song, MCE Regulatory and Legislative Policy Manager; Mike Callahan, MCE Senior Policy Counsel; Nathaniel Malcolm, MCE Policy Counsel; Jonathan Koltz, Legal Advisor to Commissioner Guzman Aceves; and Adenike Adeyeye, Chief of Staff to Commissioner Guzman Aceves. The meeting lasted approximately 30 minutes. The communication was oral and no handout was provided.

The meeting covered several topics pertaining to the comments MCE filed in Order Instituting Investigation ("OII"), and the conversation was led by Ms. Swaroop. Ms. Swaroop reflected on the recommendations put forth in MCE's opening comments which included:

[1] Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, LS Power has given MCE permission to sign this notice on their behalf.

- Separating PG&E's gas and electric lines of businesses to improve safety and support decarbonization;
- Shifting PG&E's electricity provider role to a wires-only company in order to focus on safety, grid modernization and decarbonization; and
- Launching a stakeholder process to determine an appropriate electricity generation framework that emphasizes safety, decarbonization and equity.

Additionally, Ms. Swaroop spoke about the how the growing diversification of the electricity market will require more coordination from all parties involved, and the CPUC's potential role as a forum for stakeholders to collaborate. Mr. Callahan further elaborated on MCE's resiliency efforts in managing wildfire risks, and the importance for the OII to focus on ratepayer impacts.

Respectfully submitted,

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June 7, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	)))))	Investigation 15-08-019 (Filed August 27, 2015)

MCE
THREE-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

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May 30, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	)	Investigation 15-08-019 (Filed August 27, 2015)

MCE
THREE-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission's Rules of Practice and Procedure and Public Utilities Code Section 1701.3(h)(2), MCE hereby gives advanced notice of a meeting with Adenike Adeyeye, Chief of Staff to Commissioner Guzman-Aceves, and Jonathan Koltz, Legal Advisor to Commissioner Guzman-Aceves. The meeting is scheduled on June 4, 2019 at 1:30pm. Shalini Swaroop (MCE General Counsel), CC Song (MCE Regulatory and Legislative Policy Manager), Mike Callahan (MCE Senior Policy Counsel), and Nathaniel Malcolm (MCE Policy Counsel) will be in attendance.

Respectfully submitted,

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May 30, 2019

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

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

**COMMENTS OF MARIN CLEAN ENERGY AND CITY OF LANCASTER
IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING INVITING
COMMENTS ON DRAFT POTENTIAL AND GOALS STUDY**

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May 21, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

COMMENTS OF MARIN CLEAN ENERGY AND CITY OF LANCASTER IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING INVITING COMMENTS ON DRAFT POTENTIAL AND GOALS STUDY

Marin Clean Energy ("MCE") and the City of Lancaster ("Lancaster") submit the following comments in response to the *Administrative Law Judge's Ruling Inviting Comments on Draft Potential and Goals Study* ("Ruling"), filed on May 1, 2019. As the two Community Choice Aggregators ("CCAs") who are currently administering energy efficiency ("EE") programs, MCE and Lancaster appreciate the opportunity to provide input on the "2019 Energy Efficiency Potential and Goals Study" ("Navigant Study"). MCE and Lancaster provide the following comments in an effort to engage with Navigant and the Commission to ensure that non-investor-owned utility ("IOU") EE program administrators ("PAs"), such as CCAs and Regional Energy Networks ("RENs"), are appropriately considered and distinguished from their IOU counterparts. MCE and Lancaster hope that the below comments serve to shed light on some areas where the Commission should carefully consider the Navigant Study and its relationship to non-IOU EE portfolios.

I. COMMENTS

A. The Navigant Study Should Provide Value to Both IOUs and CCAs

MCE and Lancaster believe that the Navigant Study should aim to provide as much value for CCA EE programs as it does for IOU EE programs, since the Navigant Study is funded by *all* ratepayers. Unfortunately, the Navigant study does not currently provide the same level of value to CCAs as it does to the IOUs. This is because the energy savings and potential are only identified on an IOU service territory level, and not on a CCA or REN level. This data-driven information helps the IOUs design EE portfolios in addition to assign them goals. MCE and Lancaster desire to have more detailed information on EE potential in their respective service territories to help inform future program design and development.

B. There Are Many Uncertainties Surrounding Navigant's Proposed Top-Down Disaggregation Approach for Determining Energy Savings Goals and Potential for CCAs and RENs

Lancaster and MCE are concerned about Navigant's high-level approach to parsing out savings for CCAs and RENs as proposed during a workshop in January 2019.[1] Navigant is suggesting to "conduct a top-down disaggregation of IOU level results" for CCAs and RENs as a "post-processing step based on population and historic program savings data."[2] More specifically, it is our understanding that Navigant intends to utilize population data, as well as historical energy consumption and historical energy savings data from past programs in order to understand the overlap and savings potential.

Lancaster and MCE question whether a top-down approach will be able to provide valuable feedback on savings potential to CCAs. For example, MCE's service area is very different than Pacific Gas and Electric Company's ("PG&E's") entire service area in terms of population demographics and climate zones.[3] Likewise, Lancaster's service area is very different than that of

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[1] 2019 Potential and Goals Study Workshop, January 11, 2019.
[2] PowerPoint Presentation, *2019 Potential and Goals Study Workshop*, at 30.
[3] MCE provides retail electricity generation services to customers in Marin County, Napa County and unincorporated Contra Costa County, as well as the cities of Richmond, San Pablo, El Cerrito, Walnut Creek, Lafayette, Concord, Martinez, Oakley, Pinole, Pittsburg and San Ramon and the towns of Danville and Moraga. MCE also serves the city of Benicia in Solano County.

Southern California Edison's ("SCE's").[4] Even if Navigant examined population and historic programs savings data, a top-down allocation approach will not provide the level of detail that is required to accurately assign EE potential and savings to CCAs and RENs. For example, the potential and impact of installing a heating, ventilation, and air conditioning ("HVAC") EE measure in MCE's service area will be very different than installing that same measure in the Central Valley. Therefore, a pure allocation methodology would likely be inaccurate. Furthermore, CCAs and RENs have historically been given a limited scope under the EE programs to avoid overlap with IOU programs, including administering EE programs in fewer sectors. Historical savings information will therefore be skewed to a much greater potential for IOU programs relative to non-IOU programs.

With respect to the proposed "top-down" approach, Lancaster and MCE believe that it would be helpful to understand how Navigant is determining its population for IOU versus CCA allocations. For example, it is unclear whether Navigant is actually counting CCA customers and IOU customers in the CCA's service areas, or if Navigant is simply considering all customers in the CCAs' service areas as "CCA customers." The application of this information to establish goals is also complicated because some CCA EE programs are delivered only to CCA customers while others are available to all customers (i.e., CCA and IOU customers in the CCA's service area) and the same may be true for IOU programs.

In summary, Lancaster and MCE support modifications to the Navigant Study to improve the value to CCA programs. This study should attempt to provide the same quality and character of information for use in designing CCA programs as it does for IOU programs. Lancaster and

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[4] Lancaster is a community of approximately 160,000 residents located in northern Los Angeles County, in the High Desert region of the western Mojave Desert.

MCE will be available to Navigant staff to discuss the content of these comments and opportunities to further refine the potential and goals study.

C. Response to Question #6: No Changes to the September 2019 ABALs Are Required Due to the Navigant Study

Question # 6 of the Ruling states:

> "Given the changes in potential for 2020, should there be any changes to the required components of annual budget advice letters (ABALs) due from the PAs in September 2019, and/or to the process or criteria for reviewing the September 2019 ABALs (Sections 7.2 and 7.3 of D.18-05-041)? Explain why or why not. Any recommendations in response to this question should focus on new ideas and not repeat recommendations previously made and that the Commission has already dismissed."[5]

MCE and Lancaster do not believe that there should be any changes to the required components, process or criteria for reviewing the September 2019 ABALs for all PAs. As pointed out above, energy savings goals for CCAs (and RENs) are currently *not* determined through the Navigant Study.[6] Updating the ABAL process for all PAs based on the results of the Navigant Study would therefore be partial and premature. MCE and Lancaster also believe that updating the ABAL process for just the IOU PAs would be confusing and disruptive to the EE marketplace.

III. CONCLUSION

MCE and Lancaster thank the Commission for its consideration of these comments on the Navigant Study. MCE and Lancaster look forward to continuing to work with the Commission,

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[5] Ruling at 5.

[6] MCE establishes its energy savings goals for its service territory through approval of its EE Business Plan, which the Commission approves. The current MCE Business Plan was approved in Decision ("D.")18-05-041, *Decision Addressing Energy Efficiency Business Plans*, May 31, 2018. Similarly, Lancaster provided its projected energy savings via Advice Letter and the Commission approved Lancaster's budget in Resolution E-4917. Unlike MCE, Lancaster's budget is constrained by the funding determination provided in D.14-01-033. Therefore, even if Navigant estimated potential for Lancaster's territory, the goals could not be directly derived from that number.

Navigant and other stakeholders in order to ensure that CCA programs and their customers are given appropriate and careful consideration through the course of this proceeding.

May 21, 2019

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 Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020

**COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON TRACK 3 WORKSHOP AND PROPOSALS**

CALCCA ADVANCING LOCAL ENERGY CHOICE cal-cca.org

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March 22, 2019

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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

**COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON TRACK 3 WORKSHOP AND PROPOSALS**

Pursuant to the January 29, 2019 *Amended Scoping Memo and Ruling of Assigned Commissioner*, the California Community Choice Association (CalCCA) submits these Track 3 Comments on the Energy Division's March 12-13, 2019 Track 3 workshops (Workshops) and the proposals filed by parties on March 4, 2019 (Proposals).

I. INTRODUCTION

CalCCA supports many of the proposals offered by Energy Division Staff (Staff), the investor-owned utilities and other stakeholders. These proposals, collectively, will improve Local Resource Adequacy (RA) data transparency and access, increase forecast accuracy and certainty earlier during the year and increase collaboration among LSEs to reduce post-forecast adjustments. While CalCCA addresses a number of Proposals in Section II, one issue merits emphasis. Differentiating RA requirements within a year will reduce unnecessary procurement and, consequently, reduce costs for customers. Proposals advanced by Pacific Gas and Electric Company (PG&E) and CalCCA for seasonal or monthly differentiation of Local RA requirements warrant additional exploration to determine the degree of differentiation the California Independent System Operator (CAISO) can accommodate.

II. THE COMMISSION SHOULD WORK WITH THE CAISO TO MAXIMIZE THE DEGREE OF INTRA-YEAR DIFFERENTIATION OF LOCAL RA REQUIREMENTS

The Commission should increase the differentiation of Local RA requirements within a year, taking into account CAISO's ability to accommodate further differentiation. CalCCA proposes to modify the allocation of local RA requirements to reflect each load-serving entity's (LSE) actual month-to-month load forecasts.[1] CalCCA explains its proposal:

> The inability to tailor RA purchases to actual forecast load (i) increases costs for customers of all LSEs, particularly CCAs launching new services, (ii) inflates demand unnecessarily for local RA by requiring two LSEs to procure capacity for the same customer load within the same compliance year (during years where customers migrate from one LSE to another), and (iii) shifts costs among LSEs.[2]

PG&E offers a similar proposal, which differentiates local RA requirements seasonally. PG&E proposes:

> [L]ocal requirements in each month be set based on the ratio of the local requirement to the peak demand during the peak month of the year in each region. Namely, if the local requirement in a region is X and the peak demand in the peak month is Y, the local requirement would be X/Y of the peak in each month. This would provide monthly varying local requirements."[3]

PG&E observes that Net Qualifying Capacity (NQC) values "are generally higher during summer load months…"[4] It argues that seasonal requirements "would allow generators and LSEs to better optimize outages schedules with the procured local RA resources" and would "better integrate preferred resources."[5] PG&E proposes seasonal, rather than monthly, differentiation, recognizing the influence maintenance periods and abnormal system conditions may have on non-summer needs.[6]

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[1] *California Community Choice Association Track 3 Proposals* (CalCCA Proposals), dated March 4, 2019 at 3.

[2] *Id.* at 2-3.

[3] *Track 3 Proposals of Pacific Gas and Electric Company (U 39 E)* (PG&E Proposals), dated March 4, 2019 at 7.

[4] *Id.*

[5] *Id.*

[6] *Id.*

CalCCA encourages further exploration of these proposals in Track 3 to determine the level of granularity the CAISO can accommodate in Local RA requirements without threatening local reliability. If PG&E's approach is the only feasible level of differentiation that will meet this objective, CalCCA would support seasonal differentiation.

III. THE COMMISSION SHOULD ADOPT PROPOSALS THAT INCREASE FORECAST ACCURACY AND CERTAINTY

Staff offers several recommendations to increase the accuracy and certainty of load forecasts, which CalCCA supports. As a foundation, Staff proposes to adopt a narrow definition of "load migration."[7]

> The term "load migration" means load effects that are tied directly to customer counts and that an LSE cannot reasonably predict or control, such as opt-out rates or new service requests. Load migration does not include changes to forecasting assumptions or any effect not tied to customer counts. For instance, load migration does not include changes to implementation plans, updated weather modeling or assumptions, changes to customer class load profiles, or new or updated customer load data..[8]

Second, Staff proposes a binding notice of intent (BNI) process to give greater certainty to the LSEs' initial forecast in April.[9] It proposes that the BNI "locks in" RA requirements based on load forecast assumptions in April.[10] CEC staff, however, would continue to accept forecast revisions until May 15. Third, and related, Staff proposes standards for the April load forecast.

> [I]nitial year ahead load forecasts should account for all data, assumptions, and criteria that an LSE can reasonably predict or control, including – but not necessarily limited to – implementation plans, weather modeling, customer class load profiles, and customer load data. Because the LSE can reasonably

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[7] Administrative Law Judge's Ruling on Proposals of Energy Division, March 4, 2019, Attachment 2, *Energy Division Proposals for Proceeding 17-09-020: 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 (*Staff Proposals) at 16

[8] *Id.* at 15.

[9] *Id.*at 16.

[10] *Id.*

> predict or control these data, assumptions, and criteria, they should not change between an LSE's initial (April) and final (August) year ahead load forecasts.[11]

In developing this forecast, Staff proposes that the "LSE should make reasonable 'placeholder' assumptions for any load effects that it cannot reasonably control in its initial year ahead load forecast, including – but not necessarily limited to – opt out rates and new service requests."[12]

CalCCA generally supports these proposals with three modifications. First, a redefinition of "load migration" for the purposes of forecast Local RA is reasonable, but it should be referred to as "new service load deviations" or some other term to avoid confusion with the use of the term in other contexts. Second, changes to an LSE's forecast should also be permitted following a *force majeure* event, such as a wild fire, that has material load impacts. Third, greater flexibility should be provided for newly launching community choice association (CCA) services, enabling post-April changes to ensure that the forecast used in allocating RA requirements is as accurate as possible.

SCE also offers several proposals that CalCCA supports, with clarification. CalCCA fully supports SCE's call for greater transparency into the CEC's coincidence factor estimation methodology and calculations. [13] CalCCA also supports, but with limitations, SCE's proposal for an aggregated CCA and LSE forecast. SCE observes that the "'CEC evaluates each LSE load forecast individually and performs an adjustment to reflect the LSE's load contribution to the coincident CAISO's system peak in that month.'"[14] It proposes that the CEC develop an aggregated CCA and Electric Service Providers (ESP) load forecast to provide a check on the forecasts of each individual LSE.[15] CalCCA supports this recommendation if it provides the CEC another check on its overall forecast, but is concerned about

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11 *Id.*

12 *Id.*

13 *Southern California Edison Company (U 338-#) Track 3 Proposals* (SCE Proposals), dated March 4, 2019 at 2 (quoting *Resource Adequacy 2016 Load Forecast Adjustment Methodology* – Revised, dated April 2016, by Miguel Cerrutti, Demand Analysis Office – California Energy Commission, and Donald Brooks, Energy Division – California Public Utilities Commission, at 2).

14 *Id.*

15 *Id. at 2-3.*

SCE's characterization in the workshop as the "CEC and SCE Reconciliation."[16] Any such process should make clear that the utility's load forecast data should not be deemed an accurate benchmark for the CCAs' combined forecasts. Allowing one competitor to have a strong hand in determining the Local RA requirement of another presents the potential for abuse that the Commission is bound to prevent.

IV. THE COMMISSION SHOULD ADOPT OTHER FORECAST-RELATED IMPROVEMENTS THAT WILL MINIMIZE POST-FORECAST ADJUSTMENTS

Material adjustments to LSE forecasts by the California Energy Commission (CEC) reflected in the August requirements for the 2019 RA year took LSEs by surprise. Requirements increased beyond the LSEs' forecasts; and, in some instances, the increases resulted in the need for a waiver. While the CEC's efforts to improve load forecasting for determining RA requirements will reduce the risk of these types of adjustments, CalCCA supports greater predictability and transparency in the application of either "pro rata" or plausibility adjustments.

CalCCA recommends improving this process by developing a common system-wide load forecast in an IOU's Forecast Energy Resource Recovery Application (ERRA) and by increasing coordination among LSEs and the CEC regarding the basis and need for any adjustments.[17] CalCCA also proposes establishing a system for penalties to LSEs whose actions grossly and repeatedly increase the costs for other LSEs as a result of pro rata increases in requirements.[18] The Alliance for Retail Energy Markets (AReM) similarly raised concerns about post-forecast adjustments, proposing to "improve the plausibility adjustment process by establishing clearer standards for when existing load is assumed to continue into the following year's RA compliance period."[19] To a large extent, these concerns and proposals align with Staff proposals.

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16 SCE Resource Adequacy Load Forecast, CPUC Resource Adequacy Track 3 Workshop, March 12-13, 2019 at 3.

17 CalCCA Proposals at 3-4.

18 *Id.* at 4.

19 *Track 3 Proposals of the Alliance for Retail Energy Markets* (AReM Proposals), dated March 4, 2019 at 3.

Staff proposes several measures that will address improved forecasting and address LSE concerns regarding post-forecast adjustments. CalCCA supports the following Staff proposals for "meet and confer process" to encourage greater coordination among LSEs in advance of the April forecasts.[20] This process includes:

- "[A] requirement that each IOU meet separately with each non-IOU LSE in its service territory during the annual ERRA process (before December 31) to discuss expected monthly migration from IOUs to non-IOU LSEs during the year following the coming year (i.e. the next year for which LSEs will provide year ahead forecasts)."
- A meeting before December 31 between ESPs and CCAs that expect load migration.
- A meeting of all LSEs by February 15 to discuss expected migration for the following year
- Documentation of the LSEs' interactions.

CalCCA would note that flexibility in the timing of the meeting "before December 31," discussed in the second bullet point above may be needed for newly formed CCAs or for CCAs that file amended implementation plans near the end of the year (e.g., a newly-formed CCA filing its implementation plan on December 31,2019 may need a one-on one meeting with the IOU before the "all-LSE" meeting by February 15, 2020.

CalCCA also supports Staff's proposal for greater efficiency in the data exchange between the IOUs and other LSEs.[21] Staff proposes the following:

- CCAs and ESPs must request from IOUs any load data they will use in developing their year ahead forecasts by January 15 of a given year (the year prior to the year for which they are developing forecasts),
- IOUs must provide CCAs and ESPs with the requested load data by March 1, and

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[20] Staff Proposal at 17.
[21] *Id.* at 18.

- [T]he load data IOUs provide will include three years of hourly meter data for each individual account in each jurisdiction requested by the given ESP or CCA….

CalCCA also supports Staff's proposed dispute resolution mechanism, which contemplates an informal effort to work out differences in forecasts. If the parties fail to agree within 30 days, the Energy Division will allocate differences "pair wise."[22] CalCCA notes, however, that the meaning of "pair wise" is unclear and proposes allocating the difference to the disputing parties in proportion to their relative loads.

Finally, Staff proposes that the Commission and CEC would add "plausibility review triggers" to the forecast adjustment process. Under certain circumstances, an LSE would be required to modify its forecast. Staff proposes three triggers[23]:

- If an LSE's initial year ahead load forecast for a given month (or the system RA requirement implied by adjusting for coincidence and adding a 15% PRM) deviates from the corresponding forecast (or system RA requirement) in its implementation plan by more than 5% of the latter

- If an LSE's final year ahead load forecast for a given month deviates from its corresponding initial year ahead forecast by more than 5% of the latter, or

- If an LSE's month ahead load forecast for a given month deviates from its corresponding final year ahead forecast by more than 5% of the latter.

If an LSE reaches a trigger threshold, it would be required to submit additional documentation, revise the plan to more closely conform to its implementation plan or to otherwise revise the forecast.[24] CalCCA does not oppose the trigger proposal, provided adequate coordination occurs between the agencies and the LSE, and greater dialogue is undertaken for newly launching services before automatically triggering the adjustment.

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22 *Id.*
23 *Id.* at 16-17.
24 *Id.*

V. THE COMMISSION SHOULD MAKE CLEAR WHERE OTHER PROPOSALS NOT ADDRESSED IN TRACK 3 WILL BE ADDRESSED

Parties, including CalCCA, propose a number of measures that merit consideration but may be difficult to resolve on a timeline that accommodates a June 2019 final decision. Even if these issues are not resolved in Track 3, CalCCA requests that the Commission clearly identify the forum and time for their resolution.

CalCCA proposes the adoption of a framework for short-term sales of Local RA by the IOUs, recognizing that a more holistic approach has been undertaken in Phase 2 of R.17-06-026.[25] The framework would (i) require the IOUs to offer all Local RA to the market in excess of the amount needed to serve bundled load plus a small "buffer"; (ii) establish a schedule for the IOUs' offers, possibly even employing an Electronic Bulletin Board, to ensure the products are offered sufficiently in advance of compliance dates to enable compliance by other LSEs; and (iii) establish standard terms and conditions for those sales to ensure the greatest participation in any IOU offers. Developing such a framework is critical, in light of the IOUs' continuing market power and the continuing migration of IOU load to other LSEs. If the Commission does not address this issue in Track 3, CalCCA requests that the proposal be taken up in another near-term track or other proceeding to ensure the efficient operation of the Local RA market.

The Center for Energy Efficiency and Renewable Technologies (CEERT) offers an important proposal to increase resource availability and LSE flexibility by accommodating "Portfolio NQCs" to meet Local RA requirements.[26] CEERT defines Portfolio NQC as "a collection of individual resource components in each sub-area load pocket during a contingency event that creates a real time [Local

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[25] CalCCA Proposal at 4.

[26] *Track 3 Proposals of the Center for Energy Efficiency and Renewable Technologies* (CEERT Proposals) at 4.

Capacity Requirements (LCR)] LCR need."[27] This approach would permit "any LSE that has a LCR obligation or is subject to Cost Allocation Mechanism (CAM) cost allocation for that LCR need can propose a preferred resource portfolio of resources located within the load pocket plus specific transmission upgrades to reduce that LCR need for showing in the next or subsequent RA cycles."[28] CEERT explained this potential during the March 13 workshop using a diagram presented in a recent SCE Request for Offers.

CEERT proposes that the "Portfolio NQC" be calculated for the sum of its elements "using the same study protocols used by the CAISO to determine the LCR need."[29] Mr. Caldwell explained at the workshop that the Portfolio NQC provider would be responsible to make sure that each element is dispatched in a way that meets the IOU's or CAISO's defined need. In explaining this approach, CEERT highlights The Oakland Clean Energy Project, a collaboration between PG&E and East Bay Community Energy, "to replace the most inefficient, polluting, and expensive fossil power plant in California with a portfolio of transmission upgrades, battery storage, energy efficiency and local solar."[30]

CEERT's proposal recognizes the trending of the Local RA market toward the state's policy goal of reducing greenhouse gas emissions using distributed energy resources. Rather than relying on a single, large natural-gas fired central station generator, RA needs will increasingly be met by portfolios of smaller preferred resources. The Commission should shine a light on these types of arrangements with the aim of accommodating their increased use in a near-term separate track of this proceeding.

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27 *Id.*

28 *Id.*

29 *Id.*

30 *Id.* at 2.

Finally, several parties propose to unbundle flexible RA from system and local RA.[31] While further examination may be required, CalCCA does not oppose unbundling these products, provided that LSEs may continue to engage in transactions that bundle these products.

VI. CONCLUSION

CalCCA thanks the Commission for the opportunity to comment on the Track 3 workshops and proposals and requests consideration of the recommendations offered herein.

March 22, 2019

Respectfully submitted

Evelyn Kahl

Evelyn Kahl

Counsel to the
California Community Choice Association

31 SCE Proposals at 14; *Track 3 Proposal of the California Energy Storage Alliance in Response to the Amended Scoping Memo and Ruling of Assigned Commissioner, dated March 4, 2019* at 5; *Western Power Trading Forum Track 3 Proposals, dated March 4, 2019* at 2-3.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety	Investigation 15-08-019 (Filed August 27, 2015)

MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION

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June 7, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	Investigation 15-08-019 (Filed August 27, 2015)

MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission's Rules of Practice and Procedure and Public Utilities Code Section 1701.3(h)(2), Marin Clean Energy ("MCE") hereby gives notice of the following *ex parte* communication.[1] The communication was initiated by Commissioner Guzman-Aceves' office, and occurred on June 04, 2019 at approximately 1:30 pm. The communication was held in-person at the California Public Utilities Commission in San Francisco, California. The communication was between Shalini Swaroop, MCE General Counsel; C.C. Song, MCE Regulatory and Legislative Policy Manager; Mike Callahan, MCE Senior Policy Counsel; Nathaniel Malcolm, MCE Policy Counsel; Jonathan Koltz, Legal Advisor to Commissioner Guzman Aceves; and Adenike Adeyeye, Chief of Staff to Commissioner Guzman Aceves. The meeting lasted approximately 30 minutes. The communication was oral and no handout was provided.

The meeting covered several topics pertaining to the comments MCE filed in Order Instituting Investigation ("OII"), and the conversation was led by Ms. Swaroop. Ms. Swaroop reflected on the recommendations put forth in MCE's opening comments which included:

[1] Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, LS Power has given MCE permission to sign this notice on their behalf.

- Separating PG&E's gas and electric lines of businesses to improve safety and support decarbonization;
- Shifting PG&E's electricity provider role to a wires-only company in order to focus on safety, grid modernization and decarbonization; and
- Launching a stakeholder process to determine an appropriate electricity generation framework that emphasizes safety, decarbonization and equity.

Additionally, Ms. Swaroop spoke about the how the growing diversification of the electricity market will require more coordination from all parties involved, and the CPUC's potential role as a forum for stakeholders to collaborate. Mr. Callahan further elaborated on MCE's resiliency efforts in managing wildfire risks, and the importance for the OII to focus on ratepayer impacts.

Respectfully submitted,

/s/ Daniel Settlemyer

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BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	)))))	Investigation 15-08-019 (Filed August 27, 2015)

MCE
THREE-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

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May 30, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	))))))	Investigation 15-08-019 (Filed August 27, 2015)

MCE
THREE-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission's Rules of Practice and Procedure and Public Utilities Code Section 1701.3(h)(2), MCE hereby gives advanced notice of a meeting with Adenike Adeyeye, Chief of Staff to Commissioner Guzman-Aceves, and Jonathan Koltz, Legal Advisor to Commissioner Guzman-Aceves. The meeting is scheduled on June 4, 2019 at 1:30pm. Shalini Swaroop (MCE General Counsel), CC Song (MCE Regulatory and Legislative Policy Manager), Mike Callahan (MCE Senior Policy Counsel), and Nathaniel Malcolm (MCE Policy Counsel) will be in attendance.

Respectfully submitted,

/s/ Daniel Settlemyer

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Re CalCCA Comments on Draft Resolution E-4998

To Energy Division – Tariff Unit:

The California Community Choice Association (CalCCA) submits these comments pursuant to Draft Resolution E-4998 (Draft Resolution), which approves with modifications Pacific Gas and Electric Company (PG&E) Advice Letter (AL) 5473-E.

I. INTRODUCTION AND SUMMARY

PG&E proposed in AL 5473-E to update its Bundled Procurement Plan (BPP) in response to likely changes in its position as a result of implementation of the Power Charge Indifference Adjustment (PCIA) Decision (D.) 18-10-019 and the Resource Adequacy (RA) program in Rulemaking (R.) 17-09-020. Among other things, PG&E requested authority to:

> (1) limit sales of certain RA products to delivery terms not to exceed two years forward unless offered to a central buyer; (2) require RA product sales to principally originate through PG&E-held solicitations; and (3) utilize standard contracting terms.[1]

[1] AL 5473-E at

PG&E further asks the Commission to approve PG&E's proposal not to "post collateral to support PG&E's sales of RA."

The Draft Resolution, in part, grants PG&E's requests.[2] It grants PG&E's request to sell products "principally" through PG&E-held solicitations. It further authorizes PG&E to "issue standard contract terms under its proposed Sales Framework," but acknowledges that it is a reasonable practice for PG&E to respond to proposals for modification of the contract terms.

In other respects, the Draft Resolution rejects or raises concerns regarding PG&E's requests. Granting CalCCA's request, the Draft Resolution requires PG&E to "offer resource adequacy capacity from resources located in Local Reliability Areas for delivery periods covering all three years in the multiyear framework adopted in D.19-02-022."[3] It further raises a concern regarding PG&E's proposed solicitation schedule. While it does not fully resolve these schedule concerns, it recognizes the uncertainty associated with PG&E's approach:

> Recognizing this uncertainty, we nevertheless expect that PG&E will, to the extent possible, attempt to schedule solicitations between the dates when LSEs receive relevant requirements (and credit allocations) and the dates when subsequent RA filings are due. Finally, PG&E should revise the solicitation schedule to incorporate delivery terms of local RA capacity that align with the multiyear requirements adopted in D.19-02-022. We will direct PG&E to revise its RA solicitation schedule to address these issues in the ordering paragraphs below.[4]

Unfortunately, its solution for these solicitations lacks clarity. Finally, and critically, the Draft Resolution acknowledges CalCCA's suggestion that PG&E's practice of retaining a "buffer" for bundled load may be causing withholding of Local RA products. It concludes, however, that "[t]his assertion implies a deeper discussion than we can address in a resolution."[5]

While CalCCA appreciates the Energy Division's acknowledgment of its concerns regarding PG&E's sales practices, CalCCA encourages bolder steps in two respects. The Commission

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2 Draft Resolution at 6-7.
3 Draft Resolution, Ordering Paragraph 2.b at 9.
4 Id. at 7.
5 Id. at 8.

should require PG&E to launch a solicitation for 2020 RA products within 10 business days following the effective date of the final resolution. The Commission further should urgently develop a methodology to determine PG&E's excess products for sale, pending a longer-term resolution in R.17-06-026 Track 3. Finally, the Commission should not entirely relieve PG&E from having to consider how offering collateral would create terms less favorable for their counterparties.

II. PROPOSED MODIFICATIONS TO DRAFT RESOLUTION

A. The Commission Should Direct PG&E to Launch a 2020 Solicitation Not Later Than 10 Business Days Following the Effective Date of the Final Resolution.

The Draft Resolution acknowledges concerns over PG&E's proposed solicitation schedule but does not clearly resolve the concern. Requiring PG&E to "schedule solicitations between the dates when LSEs receive relevant requirements…and the dates when subsequent RA filings are due"[6] does little to encourage PG&E to get its excess products to market on a timely basis. Technically, this language permits the utility to wait until October 30 to issue an RFO, since the compliance deadline is October 31. In fact, the Appendix S schedule submitted by PG&E contemplates the first 2020 solicitation in "September/October 2019."[7] The Commission should substantially tighten this requirement to accommodate compliance by other LSEs who rely on PG&E's excess Local RA to meet their requirements.

CalCCA requests that the Commission direct PG&E to issue its first solicitation for 2020 RA products within 10 days of the issuance of this modified Resolution. In future years, utility RA solicitations should take place in the Spring of the year preceding the reliability year (e.g. May 1, 2020 issuance for 2021 RA). In fact, a more accelerated year-ahead solicitation schedule is under consideration in R.17-06-026 Working Group #3. Applying a consistent schedule with reasonable lead time will prevent a scramble by LSEs for RA and facilitate adequate functioning of the Commission's RA program.

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6 Id. at 7.
7 AL 5473-E, PDF 93 of 105.

B. The Commission Should Immediately Develop Clear Guidance for Determining the Amount of Excess RA in PG&E's Portfolio.

CalCCA's protest contends that "PG&E's Sales Framework implicates its practices of withholding 'buffer' products to prevent penalties and to enable substitution in the event a resource is unavailable." [8] There currently are no requirements, other than general reasonableness requirements associated with PG&E's BPP, regarding how much of a "buffer" to hold to assure bundled customer compliance. And, as the Draft Resolution acknowledges: "we recognize the significant position PG&E holds in California's energy and capacity markets and expect PG&E not to wield that position towards anticompetitive ends."[9] Despite these circumstances, the Draft Resolution fails to provide any guidance, only suggesting that the issue is too complex for the resolution.

While CalCCA acknowledges that there is no specific methodology before the Commission to address this concern, CalCCA requests that the Commission emphasize the critical importance of assessing excess RA long before the 2020 compliance deadline. CalCCA recommends that the Commission set a workshop within 10 days following the effective date of the Draft Resolution to explore methodologies that will ensure that the excess RA finds its way to the market before the end of the compliance period. In anticipation of this workshop, and for market knowledge and transparency CalCCA requests that the CPUC provide aggregate data for the three IOUs (PG&E, SDG&E, SCE) from data found on LSEs RA filings. Specifically, for both the Year Ahead and Month Ahead (All months currently filed for the 2019 compliance year), the aggregate data found in Table 2 and 3 of the "Summary Year Ahead" tab, and the aggregate data found in Table 2, 3, 5, and 6 of the "Summary Month Ahead" tab.

C. PG&E should not be alleviated of all collateral requirements.

PG&E has repeatedly cited to the importance of investment-grade credit when entering into transactions with counter-parties. Posting collateral is common practice in market transactions, and is correlated with the creditworthiness of the counterparty and contract length. To now grant PG&E a special exclusion from having to consider offering collateral would create terms less favorable for their counterparties and subject those counterparties' customers to unnecessary risk.

[8] CalCCA Protest to PG&E Advice Letter E-5473, at 2.
[9] Draft Resolution at 8.

III. CONCLUSION

For all of the foregoing reasons, CalCCA requests that the Commission modify the Draft Resolution as requested herein.

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 Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020

**COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON TRACK 3 WORKSHOP AND PROPOSALS**

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Pursuant to the January 29, 2019 *Amended Scoping Memo and Ruling of Assigned Commissioner*, the California Community Choice Association (CalCCA) submits these Track 3 Comments on the Energy Division's March 12-13, 2019 Track 3 workshops (Workshops) and the proposals filed by parties on March 4, 2019 (Proposals).

I. INTRODUCTION

CalCCA supports many of the proposals offered by Energy Division Staff (Staff), the investor-owned utilities and other stakeholders. These proposals, collectively, will improve Local Resource Adequacy (RA) data transparency and access, increase forecast accuracy and certainty earlier during the year and increase collaboration among LSEs to reduce post-forecast adjustments. While CalCCA addresses a number of Proposals in Section II, one issue merits emphasis. Differentiating RA requirements within a year will reduce unnecessary procurement and, consequently, reduce costs for customers. Proposals advanced by Pacific Gas and Electric Company (PG&E) and CalCCA for seasonal or monthly differentiation of Local RA requirements warrant additional exploration to determine the degree of differentiation the California Independent System Operator (CAISO) can accommodate.

II. THE COMMISSION SHOULD WORK WITH THE CAISO TO MAXIMIZE THE DEGREE OF INTRA-YEAR DIFFERENTIATION OF LOCAL RA REQUIREMENTS

The Commission should increase the differentiation of Local RA requirements within a year, taking into account CAISO's ability to accommodate further differentiation. CalCCA proposes to modify the allocation of local RA requirements to reflect each load-serving entity's (LSE) actual month-to-month load forecasts.[1] CalCCA explains its proposal:

> The inability to tailor RA purchases to actual forecast load (i) increases costs for customers of all LSEs, particularly CCAs launching new services, (ii) inflates demand unnecessarily for local RA by requiring two LSEs to procure capacity for the same customer load within the same compliance year (during years where customers migrate from one LSE to another), and (iii) shifts costs among LSEs.[2]

PG&E offers a similar proposal, which differentiates local RA requirements seasonally. PG&E proposes:

> [L]ocal requirements in each month be set based on the ratio of the local requirement to the peak demand during the peak month of the year in each region. Namely, if the local requirement in a region is X and the peak demand in the peak month is Y, the local requirement would be X/Y of the peak in each month. This would provide monthly varying local requirements."[3]

PG&E observes that Net Qualifying Capacity (NQC) values "are generally higher during summer load months…"[4] It argues that seasonal requirements "would allow generators and LSEs to better optimize outages schedules with the procured local RA resources" and would "better integrate preferred resources."[5] PG&E proposes seasonal, rather than monthly, differentiation, recognizing the influence maintenance periods and abnormal system conditions may have on non-summer needs.[6]

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1 *California Community Choice Association Track 3 Proposals* (CalCCA Proposals), dated March 4, 2019 at 3.

2 *Id.* at 2-3.

3 *Track 3 Proposals of Pacific Gas and Electric Company (U 39 E)* (PG&E Proposals), dated March 4, 2019 at 7.

4 *Id.*

5 *Id.*

6 *Id.*

CalCCA encourages further exploration of these proposals in Track 3 to determine the level of granularity the CAISO can accommodate in Local RA requirements without threatening local reliability. If PG&E's approach is the only feasible level of differentiation that will meet this objective, CalCCA would support seasonal differentiation.

III. THE COMMISSION SHOULD ADOPT PROPOSALS THAT INCREASE FORECAST ACCURACY AND CERTAINTY

Staff offers several recommendations to increase the accuracy and certainty of load forecasts, which CalCCA supports. As a foundation, Staff proposes to adopt a narrow definition of "load migration."[7]

> The term "load migration" means load effects that are tied directly to customer counts and that an LSE cannot reasonably predict or control, such as opt-out rates or new service requests. Load migration does not include changes to forecasting assumptions or any effect not tied to customer counts. For instance, load migration does not include changes to implementation plans, updated weather modeling or assumptions, changes to customer class load profiles, or new or updated customer load data..[8]

Second, Staff proposes a binding notice of intent (BNI) process to give greater certainty to the LSEs' initial forecast in April.[9] It proposes that the BNI "locks in" RA requirements based on load forecast assumptions in April.[10] CEC staff, however, would continue to accept forecast revisions until May 15. Third, and related, Staff proposes standards for the April load forecast.

> [I]nitial year ahead load forecasts should account for all data, assumptions, and criteria that an LSE can reasonably predict or control, including – but not necessarily limited to – implementation plans, weather modeling, customer class load profiles, and customer load data. Because the LSE can reasonably

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7 Administrative Law Judge's Ruling on Proposals of Energy Division, March 4, 2019, Attachment 2, *Energy Division Proposals for Proceeding 17-09-020: 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 (*Staff Proposals) at 16

8 *Id.* at 15.

9 *Id.*at 16.

10 *Id.*

> predict or control these data, assumptions, and criteria, they should not change between an LSE's initial (April) and final (August) year ahead load forecasts.[11]

In developing this forecast, Staff proposes that the "LSE should make reasonable 'placeholder' assumptions for any load effects that it cannot reasonably control in its initial year ahead load forecast, including – but not necessarily limited to – opt out rates and new service requests."[12]

CalCCA generally supports these proposals with three modifications. First, a redefinition of "load migration" for the purposes of forecast Local RA is reasonable, but it should be referred to as "new service load deviations" or some other term to avoid confusion with the use of the term in other contexts. Second, changes to an LSE's forecast should also be permitted following a *force majeure* event, such as a wild fire, that has material load impacts. Third, greater flexibility should be provided for newly launching community choice association (CCA) services, enabling post-April changes to ensure that the forecast used in allocating RA requirements is as accurate as possible.

SCE also offers several proposals that CalCCA supports, with clarification. CalCCA fully supports SCE's call for greater transparency into the CEC's coincidence factor estimation methodology and calculations. [13] CalCCA also supports, but with limitations, SCE's proposal for an aggregated CCA and LSE forecast. SCE observes that the "'CEC evaluates each LSE load forecast individually and performs an adjustment to reflect the LSE's load contribution to the coincident CAISO's system peak in that month.'"[14] It proposes that the CEC develop an aggregated CCA and Electric Service Providers (ESP) load forecast to provide a check on the forecasts of each individual LSE.[15] CalCCA supports this recommendation if it provides the CEC another check on its overall forecast, but is concerned about

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11 *Id.*

12 *Id.*

13 *Southern California Edison Company (U 338-#) Track 3 Proposals* (SCE Proposals), dated March 4, 2019 at 2 (quoting *Resource Adequacy 2016 Load Forecast Adjustment Methodology* – Revised, dated April 2016, by Miguel Cerrutti, Demand Analysis Office – California Energy Commission, and Donald Brooks, Energy Division – California Public Utilities Commission, at 2).

14 *Id.*

15 *Id. at 2-3.*

SCE's characterization in the workshop as the "CEC and SCE Reconciliation."[16] Any such process should make clear that the utility's load forecast data should not be deemed an accurate benchmark for the CCAs' combined forecasts. Allowing one competitor to have a strong hand in determining the Local RA requirement of another presents the potential for abuse that the Commission is bound to prevent.

IV. THE COMMISSION SHOULD ADOPT OTHER FORECAST-RELATED IMPROVEMENTS THAT WILL MINIMIZE POST-FORECAST ADJUSTMENTS

Material adjustments to LSE forecasts by the California Energy Commission (CEC) reflected in the August requirements for the 2019 RA year took LSEs by surprise. Requirements increased beyond the LSEs' forecasts; and, in some instances, the increases resulted in the need for a waiver. While the CEC's efforts to improve load forecasting for determining RA requirements will reduce the risk of these types of adjustments, CalCCA supports greater predictability and transparency in the application of either "pro rata" or plausibility adjustments.

CalCCA recommends improving this process by developing a common system-wide load forecast in an IOU's Forecast Energy Resource Recovery Application (ERRA) and by increasing coordination among LSEs and the CEC regarding the basis and need for any adjustments.[17] CalCCA also proposes establishing a system for penalties to LSEs whose actions grossly and repeatedly increase the costs for other LSEs as a result of pro rata increases in requirements.[18] The Alliance for Retail Energy Markets (AReM) similarly raised concerns about post-forecast adjustments, proposing to "improve the plausibility adjustment process by establishing clearer standards for when existing load is assumed to continue into the following year's RA compliance period."[19] To a large extent, these concerns and proposals align with Staff proposals.

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[16] SCE Resource Adequacy Load Forecast, CPUC Resource Adequacy Track 3 Workshop, March 12-13, 2019 at 3.

[17] CalCCA Proposals at 3-4.

[18] *Id.* at 4.

[19] *Track 3 Proposals of the Alliance for Retail Energy Markets* (AReM Proposals), dated March 4, 2019 at 3.

Staff proposes several measures that will address improved forecasting and address LSE concerns regarding post-forecast adjustments. CalCCA supports the following Staff proposals for "meet and confer process" to encourage greater coordination among LSEs in advance of the April forecasts.[20] This process includes:

- "[A] requirement that each IOU meet separately with each non-IOU LSE in its service territory during the annual ERRA process (before December 31) to discuss expected monthly migration from IOUs to non-IOU LSEs during the year following the coming year (i.e. the next year for which LSEs will provide year ahead forecasts)."
- A meeting before December 31 between ESPs and CCAs that expect load migration.
- A meeting of all LSEs by February 15 to discuss expected migration for the following year
- Documentation of the LSEs' interactions.

CalCCA would note that flexibility in the timing of the meeting "before December 31," discussed in the second bullet point above may be needed for newly formed CCAs or for CCAs that file amended implementation plans near the end of the year (e.g., a newly-formed CCA filing its implementation plan on December 31,2019 may need a one-on one meeting with the IOU before the "all-LSE" meeting by February 15, 2020.

CalCCA also supports Staff's proposal for greater efficiency in the data exchange between the IOUs and other LSEs.[21] Staff proposes the following:

- CCAs and ESPs must request from IOUs any load data they will use in developing their year ahead forecasts by January 15 of a given year (the year prior to the year for which they are developing forecasts),
- IOUs must provide CCAs and ESPs with the requested load data by March 1, and

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[20] Staff Proposal at 17.
[21] *Id.* at 18.

- [T]he load data IOUs provide will include three years of hourly meter data for each individual account in each jurisdiction requested by the given ESP or CCA….

CalCCA also supports Staff's proposed dispute resolution mechanism, which contemplates an informal effort to work out differences in forecasts. If the parties fail to agree within 30 days, the Energy Division will allocate differences "pair wise."[22] CalCCA notes, however, that the meaning of "pair wise" is unclear and proposes allocating the difference to the disputing parties in proportion to their relative loads.

Finally, Staff proposes that the Commission and CEC would add "plausibility review triggers" to the forecast adjustment process. Under certain circumstances, an LSE would be required to modify its forecast. Staff proposes three triggers[23]:

- If an LSE's initial year ahead load forecast for a given month (or the system RA requirement implied by adjusting for coincidence and adding a 15% PRM) deviates from the corresponding forecast (or system RA requirement) in its implementation plan by more than 5% of the latter

- If an LSE's final year ahead load forecast for a given month deviates from its corresponding initial year ahead forecast by more than 5% of the latter, or

- If an LSE's month ahead load forecast for a given month deviates from its corresponding final year ahead forecast by more than 5% of the latter.

If an LSE reaches a trigger threshold, it would be required to submit additional documentation, revise the plan to more closely conform to its implementation plan or to otherwise revise the forecast.[24] CalCCA does not oppose the trigger proposal, provided adequate coordination occurs between the agencies and the LSE, and greater dialogue is undertaken for newly launching services before automatically triggering the adjustment.

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22 *Id.*
23 *Id.* at 16-17.
24 *Id.*

V. THE COMMISSION SHOULD MAKE CLEAR WHERE OTHER PROPOSALS NOT ADDRESSED IN TRACK 3 WILL BE ADDRESSED

Parties, including CalCCA, propose a number of measures that merit consideration but may be difficult to resolve on a timeline that accommodates a June 2019 final decision. Even if these issues are not resolved in Track 3, CalCCA requests that the Commission clearly identify the forum and time for their resolution.

CalCCA proposes the adoption of a framework for short-term sales of Local RA by the IOUs, recognizing that a more holistic approach has been undertaken in Phase 2 of R.17-06-026.[25] The framework would (i) require the IOUs to offer all Local RA to the market in excess of the amount needed to serve bundled load plus a small "buffer"; (ii) establish a schedule for the IOUs' offers, possibly even employing an Electronic Bulletin Board, to ensure the products are offered sufficiently in advance of compliance dates to enable compliance by other LSEs; and (iii) establish standard terms and conditions for those sales to ensure the greatest participation in any IOU offers. Developing such a framework is critical, in light of the IOUs' continuing market power and the continuing migration of IOU load to other LSEs. If the Commission does not address this issue in Track 3, CalCCA requests that the proposal be taken up in another near-term track or other proceeding to ensure the efficient operation of the Local RA market.

The Center for Energy Efficiency and Renewable Technologies (CEERT) offers an important proposal to increase resource availability and LSE flexibility by accommodating "Portfolio NQCs" to meet Local RA requirements.[26] CEERT defines Portfolio NQC as "a collection of individual resource components in each sub-area load pocket during a contingency event that creates a real time [Local

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[25] CalCCA Proposal at 4.

[26] *Track 3 Proposals of the Center for Energy Efficiency and Renewable Technologies* (CEERT Proposals) at 4.

Capacity Requirements (LCR)] LCR need."[27] This approach would permit "any LSE that has a LCR obligation or is subject to Cost Allocation Mechanism (CAM) cost allocation for that LCR need can propose a preferred resource portfolio of resources located within the load pocket plus specific transmission upgrades to reduce that LCR need for showing in the next or subsequent RA cycles."[28] CEERT explained this potential during the March 13 workshop using a diagram presented in a recent SCE Request for Offers.

CEERT proposes that the "Portfolio NQC" be calculated for the sum of its elements "using the same study protocols used by the CAISO to determine the LCR need."[29] Mr. Caldwell explained at the workshop that the Portfolio NQC provider would be responsible to make sure that each element is dispatched in a way that meets the IOU's or CAISO's defined need. In explaining this approach, CEERT highlights The Oakland Clean Energy Project, a collaboration between PG&E and East Bay Community Energy, "to replace the most inefficient, polluting, and expensive fossil power plant in California with a portfolio of transmission upgrades, battery storage, energy efficiency and local solar."[30]

CEERT's proposal recognizes the trending of the Local RA market toward the state's policy goal of reducing greenhouse gas emissions using distributed energy resources. Rather than relying on a single, large natural-gas fired central station generator, RA needs will increasingly be met by portfolios of smaller preferred resources. The Commission should shine a light on these types of arrangements with the aim of accommodating their increased use in a near-term separate track of this proceeding.

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27 *Id.*
28 *Id.*
29 *Id.*
30 *Id.* at 2.

Finally, several parties propose to unbundle flexible RA from system and local RA.[31] While further examination may be required, CalCCA does not oppose unbundling these products, provided that LSEs may continue to engage in transactions that bundle these products.

VI. CONCLUSION

CalCCA thanks the Commission for the opportunity to comment on the Track 3 workshops and proposals and requests consideration of the recommendations offered herein.

March 22, 2019

Respectfully submitted

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[31] SCE Proposals at 14; *Track 3 Proposal of the California Energy Storage Alliance in Response to the Amended Scoping Memo and Ruling of Assigned Commissioner, dated March 4, 2019* at 5; *Western Power Trading Forum Track 3 Proposals, dated March 4, 2019* at 2-3.