March 21, 2019

TO: MCE Board of Directors

FROM: Shalini Swaroop, General Counsel

RE: Policy Update on Regulatory and Legislative Items (Non-Agenda Item)

Dear Board Members:

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

I. California Public Utilities Commission (CPUC)

a. PG&E 2019 Energy Resource Recovery Account (ERRA) Forecast Proceeding

In February, the CPUC issued a Final Decision adopting PG&E's 2019 PCIA revenue requirement. This revenue requirement is used to calculate the 2019 PCIA rate charged to MCE customers. This ERRA proceeding was forum to implement many of the PCIA modifications adopted in Phase I of the PCIA Proceeding.

The annual ERRA decision is typically issued in December to allow PG&E to update its rates, including the PCIA, effective January 1 of each year. However, due to complexities arising from interpreting and implementing the PCIA Decision, the Final Decision and the resulting rate changes are delayed substantially more than in past years. MCE expects PG&E to implement the 2019 PCIA rate effective May 1.

Due to extensive MCE and CCA advocacy, the Final Decision adopted a PCIA revenue requirement approximately $120 million less than what PG&E requested. This reduction in the PCIA revenue requirement will result in a lower 2019 PCIA for MCE customers. The Final Decision also adopted a true-up of 2018 brown power prices, which MCE expects to result in additional material reductions in the PCIA revenue requirement and further reductions in the 2019 PCIA rate.

PG&E will file an implementation advice letter by March 19. This advice letter will provide the final PCIA revenue requirement calculation, taking into consideration the brown power true-up. The information in this advice letter will clarify the PCIA rate and help inform MCE's 2019 rate changes.

b. PG&E Safety and Restructuring Proceeding

In December 2018, the CPUC commenced a new phase in a long-standing CPUC proceeding to investigate PG&E's safety culture and possible restructuring. This phase of the proceeding is spurred by continued CPUC concerns that PG&E, as currently structured, is unable to provide safe and reliable energy services given wildfires in recent years.

The CPUC solicited comments from stakeholders on an array of issues ranging from PG&E's corporate governance and board composition to more existential questions about what services PG&E should provide to customers in the future. Issues within the scope of the proceeding are: (1) changes in corporate management; (2) separating PG&E into gas and electricity businesses; (3) dividing PG&E into smaller regional utilities; and (4) whether PG&E should be transitioned to a publicly owned utility and/or whether PG&E should transition out of the retail generation business and operate exclusively as an owner and operator of the transmission and distribution systems.

MCE submitted Opening Comments on the CPUC Scoping Memo. These comments supported: separating PG&E into separate gas and electricity entities; facilitating the expansion of customer choice and municipalization; increasing transparency of the distribution system to improve CCAs' and other LSEs' abilities to decarbonize the grid and improve reliability; and transitioning PG&E out of the retail generation business.

MCE joined with other Northern California CCAs in submitting Reply Comments. These Reply Comments amplified other parties' support of transitioning PG&E out of the retail generation business and encouraged the CPUC to explore ways to facilitate this transition, increase community control of retail energy generation services, and develop a more transparent, neutral, and open-access distribution system that will help improve reliability and safety.

c. Power Charge Indifference Adjustment Proceeding

i. PCIA Phase II

The PCIA Decision issued in 2018 ordered a second phase of the proceeding to address a number of unresolved issues, including how to design a true-up of the annual PCIA, methods to reduce IOUs' portfolio costs, and development of a methodology for CCAs to pre-pay their PCIA liability. The CPUC held a prehearing conference in December 2018 and issued a Scoping Memo in January officially commencing this second phase and setting the issues within scope.

In contrast to the first phase, PCIA Phase II is primarily an informal, collaborative working group effort. The Scoping Memo created several informal working groups tasked with developing consensus proposals for the CPUC to consider. As indicated above, these issues include: (1) how to set and true-up the annual benchmarks used to value the utilities' portfolios and set an appropriate PCIA; (2) how to implement PCIA pre-payment methodology; and (3) how to reduce IOU portfolio costs and optimize IOU portfolios.

MCE is participating in these working groups as a member of CalCCA. These working groups will meet over the coming months to develop consensus proposals that will be submitted to the CPUC over the course of 2019. The CPUC expects to issue a final decision on the proposed true-up/benchmarking methodologies in September 2019. The CPUC expects to issue a decision on the pre-payment issue in early 2020 and a decision on portfolio optimization and cost reduction in mid-2020.

ii. Applications for Rehearing of the PCIA Decision

In November 2018, MCE participated in filing 2 Applications for Rehearing (AfR) at the CPUC that challenged conclusions within the PCIA Decision. An AfR was filed by CalCCA and a separate Joint AfR was filed by MCE, Sonoma Clean Power and Peninsula Clean Energy.

The AfRs challenged the PCIA Decision's legal conclusions that pre-2002 utility-owned generation (UOG) is statutorily permitted to be included in the PCIA and that cost recovery for post-2002 UOG is permitted for the life of the resource. Both legal conclusions result in increased and long-lasting costs imposed on CCA customers.

The AfRs also argued as a matter of law that the CPUC's valuation methodology for Resource Adequacy and Renewables Portfolio Standard resources results in an illegal cost-shift to CCA customers. Finally, the AfRs challenged as a matter of law the CPUCs silence on whether PG&E's past forecasting practices resulted in an inflated portfolio costs that are illegally attributed to CCA customers.

Filing the AfRs preserved CalCCA's and MCE's right to seek judicial review of the PCIA Decision in state court. MCE is awaiting a CPUC decision addressing the AfRs.

d. **Resource Adequacy (RA) Proceeding**

On February 21, 2019, the CPUC adopted a multi-year requirement for Local RA resources in the RA proceeding, and delayed the implementation of a full Local RA procurement Central Buyer.

Prior to the adoption of the Decision, Load Serving Entities (LSEs) were only required to procure Local RA resources on a one-year forward basis. The multi-year requirement directs LSEs to procure 100% of their Local RA needs on a forward compliance basis for Year 1 and Year 2, and 50% for Year 3. While the CPUC originally directed the IOUs to serve as Central Buyers for each of their distribution territories, the CPUC found the proposal unviable at this time due to the PG&E bankruptcy filing, and the downgrade of SCE's and SDG&E's credit rating.

While it was a positive development that the CPUC did not adopt a Central Buyer framework this year, implementing a multi-year procurement requirement may still result in LSEs incurring stranded costs if a full procurement Central Buyer is adopted later.

The CPUC has directed the IOUs, CCAs, and Energy Service Providers (ESPs) to lead a series of workshop to develop a Central Buyer proposal that can be adopted for compliance year 2021. MCE continues to closely coordinate with other CCAs through CalCCA to raise the concerns related to stranded costs, and put forth proposals to improve other aspects of the RA program, such as better forecast coordination and alignment between the CPUC, the CEC, and the CAISO.

II. <u>California Energy Commission (CEC)</u>

a. AB 1110 Draft Regulations Released

The CEC released the Update to Power Source Disclosure (PSD) Draft Regulations on February 20, 2019. The Draft Regulations continue to attribute Greenhouse Gas (GHG) emissions to Bucket 2 renewable resources based on its substitute power, and unbundled Renewable Energy Credits (RECs) are not categorized as eligible renewable resources under the Draft Regulations.

Additionally, the CEC held a workshop on March 6, 2019, during which a CPUC Energy Division staff made a presentation on attributing the emissions associated with Cost Allocation Mechanism (CAM) resources and CAM-like resources to all electricity retail providers. MCE staff raised these points in response to the CAM presentation at the workshop: 1) Including CAM in the PSD program is inconsistent with the express directive of AB 1110, where electricity retail providers disclose the energy resources they have procured on behalf of their customers; and 2) including CAM in the PSD program is likely going to be administratively burdensome, and may lead to double counting of emissions.

The CEC is soliciting comments from all stakeholders on this issue and other parts of the Draft Regulations. The comments will be due on March 20, 2019. MCE staff is coordinating with CalCCA to provide comments that will 1) highlight the cost impact of the proposed emissions and 2) oppose the inclusion of CAM and CAM-like resources in the PSD program.

III. Bills in the California Legislature

This is a list of the most pertinent bills for MCE at this time. Given historic shifts in the energy industry, including PG&E's bankruptcy, this session is likely going to have the most intense activity on energy issues that MCE has seen. Bills have only recently been introduced and should begin being heard in policy committees in late March.

a. SB 295 (McGuire)

This is a spot bill that will likely affect CCA interests.

b. AB 56 (Garcia)

This bill would require the CPUC and the CEC to provide to the Legislature a joint assessment of options for establishing a central statewide entity to procure electricity for all end-use customers in the state by March 31, 2020. This bill would likely increase costs for CCA customers and undermine CCA local governance.

c. AB 1584 (Quirk)

This bill would require the CPUC to develop and use methodologies for allocating costs imposed on the electrical system by each load-serving entity (LSE) based on the LSE's portfolio's contribution to the electric system conditions that created those costs. This bill would likely increase costs for CCA customers.

d. AB 1513 (Holden)

This bill authorizes an electrical corporation to assign all or part of a contract for procuring eligible RPS resources to a retail seller, local publicly owned electric utility, or other; so long as the application to do so is approved by the CPUC. This bill affects the current structure of the energy market and has implications for the PCIA.

e. SB 772 (Bradford)

This bill would require CAISO to complete a competitive solicitation process for the procurement of one or more long duration energy storage projects that in aggregate have 2,000 < x <4,000 MW capacity. The solicitation process will provide for cost recovery for LSEs within CAISO's electrical grid if they deem the costs just and reasonable and that takes into account the distribution of benefits from storing the energy. This procurement would have both cost implications for CCA customers and local governance implications for CCA boards.

f. SB 350 (Hertzberg)

This bill would authorize the CPUC to consider a multiyear centralized RA mechanism, among other options, to most efficiently and equitably meet specified RA goals. This bill would have cost implications for CCA customers and local governance implications for CCA boards.

g. SB 520 (Hertzberg)

This bill would authorize the CPUC to develop threshold attributes for a load-serving entity to serve as the Provider of Last Resort (POLR); and to establish a structure, such as an auction, to determine which LSE should serve as POLR, and what benefits an LSE would receive if selected. This bill has implications for CCA operations and cost allocation for CCA customers.

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

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment

R.17-06-026
(Filed June 29, 2017)

APPLICATION OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION, CLEANPOWERSF AND SOLANA ENERGY ALLIANCE FOR REHEARING OF DECISION 18-10-019

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BEFORE THE PUBLIC UTILITIES COMMISSION
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APPLICATION OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION, CLEANPOWERSF AND SOLANA ENERGY ALLIANCE FOR REHEARING OF DECISION 18-10-019

Pursuant to Public Utilities Code sections 1731-1732 and Rule 16 of the California Public Utilities Commission's (CPUC or Commission) Rules of Practice and Procedure, the California Community Choice Association (CalCCA), Solana Energy Alliance, and CleanPowerSF submit this Application for Rehearing of Decision (D.) 18-10-019 (Decision), which was mailed on October 19, 2018. CalCCA, CleanPowerSF and Solana Energy Alliance are referred to herein collectively as the "CCA Parties."

This application is timely filed and served on the first business day following 30 days after the Commission Decision was issued.[1]

I. INTRODUCTION AND EXECUTIVE SUMMARY

The Commission has failed to proceed in the manner required by law in rendering Decision 18-10-019 (Decision), which establishes a framework for calculating the Power Charge Indifference Adjustment (PCIA). The Decision includes costs in the PCIA that the Legislature has mandated be excluded and sets a market price benchmark that fails to reduce the investor-owned utilities' (IOUs') resource portfolio costs recovered through the PCIA by the value of the benefits received by bundled customers as required by statute. In these ways, the Decision

[1] *See* Rule 16.1(a), Commission Rules of Practice and Procedure; Cal. Pub. Util. Code, § 1731(b)(1).

artificially inflates the PCIA rate that must be paid by Community Choice Aggregation (CCA) departing load customers and thus shifts costs from bundled to departing load customers. The cost shift adversely affects CCAs and their customers, while directly benefitting the bundled customers of CCAs' competitors through an artificially reduced generation charge.

The California Constitution and the provisions of the Public Utilities Code [2]confer on the Commission broad authority to regulate IOUs under its purview. The Commission's broad authority, however, is not without bounds. The Commission's exercise of its authority is "[s]ubject to statute and due process."[3] In other words, the Commission must follow and give effect to the law in its proceedings.

In issuing Decision 18-10-019, however, it has not met these requirements. Specifically, the Commission has erred by:

1. Failing to exclude the costs of utility-owned generation (UOG) in the PCIA imposed on CCA departing load customers, contrary to statute;

2. Failing to reduce the net PCIA portfolio costs of the IOUs by the value of any benefits that remain with bundled service customers, contrary to statute; and

3. Failing to exclude from the PCIA portfolio costs that are not "unavoidable" or "attributable to" departing load customers, contrary to statute.

Moreover, the Commission has failed to make findings on key issues and has drawn conclusions without substantial evidence. As discussed in greater detail below, the CCA Parties respectfully request that the Commission grant rehearing to remedy these legal errors, in accordance with

[2] Unless otherwise indicated, all statutory references herein are to the California Public Utilities Code.

[3] Cal. Const. Art. XII, § 2.

Article 16 of the its Rules of Practice and Procedure and Public Utilities Code sections 1731 and 1732.[4]

II. REQUEST FOR EXPEDITED ACTION

The Commission should act expeditiously on this application for rehearing to prevent further impairment and disruption of California's legislatively mandated CCA program. In some cases, the Decision will result in substantial increases to PCIA rates that prevent CCAs from serving their customers at the same total generation rates that the Decision enables an IOU to charge its customers. In other cases, the PCIA rates and the surrounding uncertainty may cause other CCAs to suspend or cancel the launch of service to new customers altogether. To avoid these outcomes, the CCA Parties respectfully request that the Commission expeditiously correct the legal errors in D.18-10-019, as described below. But if the Commission is unwilling to do so, it should nevertheless move quickly on rehearing given the urgency of these issues so that the CCA Parties may promptly pursue legal remedies through a petition for writ of review by an appellate court.

III. THE DECISION ERRS BY INCLUDING UTILITY-OWNED GENERATION COSTS IN THE PCIA CHARGED TO CCA DEPARTING LOAD CUSTOMERS

The Commission summarily dispenses with CalCCA's contention that, as a matter of law, UOG costs must be excluded from the scope of PCIA-eligible costs recovered from CCA departing load. Basing its conclusion, apparently, on a case only mentioned in a footnote without analysis,[5] the Commission erroneously concludes that it does "not read section 366.2(f)

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[4] The CalCCA Parties support the Application for Rehearing of Peninsula Clean Energy Authority, Marin Clean Energy, and Sonoma Clean Power Authority of Decision 18-10-019.

[5] D.18-10-019 at 52, n. 109; *Association of California Ins. Companies v. Jones* (2017) 2 Cal.5th 376.

as an exclusive list of PCIA-eligible costs."[6] The Commission finds that reading section 366.2(f) as an exclusive list would read part of 366.2(f) and 365.2 "out of the law"[7] and "render the statute inconsistent with its own subdivision (g)."[8] Neither of these conclusions is correct. The statutory provisions at issue are easily harmonized, a task that the California Supreme Court has deemed "fundamental" in any statutory construction.[9] Even if the provisions could not be harmonized, however, the Decision errs in its application of the canons of statutory interpretation and contradicts the Legislature's intent in finding that UOG costs are recoverable through the PCIA. The CCA Parties request that the Commission reverse Conclusions of Law 12 and 13 and find that all UOG costs—both ore-2002 UOG (Legacy UOG) and post-2002 UOG costs—must be excluded from the PCIA-eligible costs recovered from CCA departing load.

A. The Legislature Has Consistently Delineated the Scope of Costs That May Be Imposed on CCA Departing Load Customers

Beginning with AB 1890 (1996)[10] and following through SB 350 (2015)[11], the Legislature has established a clear and unambiguous set of costs that may be recovered from departing load (DL) customers. Nothing in any of these statutes permits the Commission to impose the costs of UOG, regardless of the date the UOG became operational, on CCA customers. Each time the Legislature has added amounts which may be recovered through the PCIA, it has done so explicitly in statute. This indicates the Legislature's continuing intention that such increases only be done through specific statutory language. Consequently, the Commission may impose UOG-related costs on CCAs only to the extent costs fall within the

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6 D.18-10-019 at 52.
7 *Id.*
8 *Id.*
9 *Wells v. Marina City Properties, Inc.* (1981) 29 Cal. 3d 781, 788.
10 Assembly Bill 1890 (Stats. 1996, ch. 854) (hereafter, AB 1890).
11 Senate Bill 350 (Stats. 2015, ch. 547) (hereafter, SB 350).

scope specified in sections 454.51(c), 454.52(c), 365.1(c)(2)(A) or 365.1(c)(2)(C). The Commission thus errs in determining that UOG costs of any kind should be included in the PCIA calculation.

1. The Legislature Permitted the Recovery of Legacy UOG Stranded Costs in AB 1890 but Directed an End to Such Recovery by 2005

AB 1890, enacted in 1996, first addressed the issue of cost recovery for utility generation assets in the context of the planned transition to a competitive market. AB 1890 allowed the utilities to recover above-market sunk costs of resources that would become uneconomic in the transition through a nonbypassable charge payable by all customers, the "Competition Transition Charge" or "CTC." The Legislature expressly included UOG within the scope of the CTC[12] and made clear its intent to fully recover any such costs by 2005.[13] In fact, in implementing AB 1890, the Commission observed: "With the exception of CTC arising from existing contracts, *no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005*."[14] The utilities were given clear notice that California was transitioning to a more competitive retail market structure and had a chance at that time to address uneconomic UOG.[15] Public Utilities Code section 367 is still in force and the Legislature has not rescinded the limits on cost recovery for UOG. In fact, there is a legitimate question as to whether *any* of the Legacy UOG costs are recoverable from *any* customers.

2. The Legislature Was Fully Aware of Legacy UOG When AB 117 Was Enacted but Declined to Include the Associated Costs in the Specific

12 *See* Cal. Pub. Util. Code, § 367.

13 D.95-12-063 at 237.

14 *Id.* at 325 (Conclusion of Law 69)(emphasis added).

15 *See, e.g.,* D.95-12-063 at 494 ("Our proposal contemplates a five-year transition period during which some utility generation assets will remain under the ownership of the utility and our regulation, while others undergo a market valuation process and possibly a transfer of ownership."); *see also* Cal. Pub. Util. Code, §§ 367(b) and 390(c).

List of Costs That May Be Recovered from CCA Departing Load Customers

In 2002, the Legislature authorized Community Choice Aggregation through the enactment of Assembly Bill 117, which included an unambiguous directive regarding the costs that must be recovered from CCA customers to prevent a cost shift to bundled customers. The Legislature mandated a "cost-recovery mechanism to be imposed on the community choice aggregator pursuant to subdivisions (d), (e), and (f) [of section 366.2]…."[16] Those subdivisions require CCA departing load customers to bear responsibility for several specific categories of costs, including Department of Water Resources bond charges,[17] Department of Water Resources' "estimated net unavoidable electricity purchase contract costs,"[18] "unrecovered past undercollections for electricity purchases, including any financing costs," [19] and a CCA customer's share of the electrical corporation's "[e]stimated net unavoidable electricity costs ….reduced by the value of any benefits that remain with bundled service customers."[20] AB 117 was enacted in 2002, well after the Legislature addressed the issue of UOG in AB 1890. Thus, at the time of AB 117's passing the Legislature was well aware of the existence of UOG, and whether and how such costs could be recovered from departing load. Despite the Legislature's clear awareness, nothing in AB 117 directs or permits the Commission to impose these costs on CCA customers.

CCAs have not been able to raise the inclusion of UOG in the PCIA until this rulemaking because the Commission has in individual ERRA proceedings repeatedly rejected any challenges to the methodology. The treatment of UOG for CCAs is a new issue. As discussed below in Section III, the issue of inclusion of UOG with respect to DA customers is rooted in the economics applicable at that time and the specific circumstances of DA customers when departure was first contemplated and

16 Cal. Pub. Util. Code, § 366.2(c)(5).
17 Cal. Pub. Util. Code, § 366.2(e)(1).
18 Cal. Pub. Util. Code, § 366.2(f)(2).
19 Cal. Pub. Util. Code, § 366.2(f)(1).
20 Cal. Pub. Util. Code, §§ 366.2(g).

then suspended. Neither the policy nor the logic pertains to CCAs departing now, and those decisions should not dictate the treatment of departing CCA customers.

3. Additional Departing Load Charges Have Been Expressly and Specifically Added by the Legislature Without the Inclusion of UOG Costs

The Legislature next spoke on the cost-shift issue in 2005, enacting a resource adequacy mandate to be applied to all LSEs, including CCAs, and adding certain RA costs to the costs directed to be recovered from CCA departing load.[21] The statute provides that reasonable system and local area reliability costs incurred by a utility "shall be fully recoverable from those customers on whose behalf the costs are incurred, as determined by the commission, at the time the commitment to incur the cost is made, on a fully nonbypassable basis…."[22] To avoid duplicating its prior directive in AB 117, the Legislature required the Commission to "exclude any amounts authorized to be recovered pursuant to Section 366.2 when authorizing the amount of costs to be recovered from customers of a community choice aggregator…."[23] Direct access customers, the other class of departed load customers, were not expressly excluded from the costs authorized in section 366.2. The care given by the Legislature in framing the departing load customers from whom costs could be recovered, and referring specifically to 366.2, again suggests that the Legislature intended to limit the scope of charges assessable to CCA customers to those it had expressly specified in statute.

In 2015, in SB 350, the Legislature addressed cost shifting in adopting the requirement for Load Serving Entities (LSEs) to submit Integrated Resource Plans (IRPs). To prevent cost shifting in either direction as a result of the IRPs, the statute provides that "the net costs of any incremental renewable energy integration resources procured by an electrical corporation to satisfy the need identified in subdivision (a) are allocated on a fully nonbypassable basis consistent with the treatment

21 Cal. Pub. Util. Code, § 380.

22 Cal. Pub. Util. Code, § 380(g).

23 *Id*.

of costs identified in paragraph (2) of subdivision (c) of Section 365.1."[24] It also permitted CCAs to propose renewable integration resources to satisfy their share of any identified need.[25]

Finally, also in SB 350, the Legislature prohibited cost shifting as a result of "additional procurement" authorized under the IRP process authorized by the statute.[26] At the same time, it made certain that the Commission's allocation of a utility's "additional procurement" costs did not disrupt the authorization in §454.51 for CCAs to "self-provide renewable integration resources."[27]

Over time, the Legislature has thus carefully framed and limited the scope of costs CCA departing load customers must bear to prevent cost shifts to bundled customers. Each time it has increased the costs that may be recovered from CCA departing load customers, the Legislature has done so via specific statutory language. Two conclusions may thus be drawn. First, the Legislature intended that any increases in departing load costs must be authorized by specific statutory language. Second, because at all times since the authorization of CCAs the Legislature has been fully aware of UOG costs, the Legislature's failure to specifically authorize the recovery of these costs from CCA departing load —in fact, the Legislature's explicit steps to distinguish DA and CCA customers—indicates its determination that such costs be excluded from the calculation.

B. Excluding UOG Costs from the PCIA Harmonizes Relevant Statutes

The cardinal rule in statutory construction is to ascertain the Legislature's intent.[28] As the court of appeal has noted, "[w]hen two statutes potentially conflict, our first task is not to declare a winner, but instead to find a way, if possible, to avoid the conflict."[29] The Decision, however, errs in failing to harmonize key statutory provisions. The Decision disagrees that

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24 Cal. Pub. Util. Code, § 454.51(c).
25 Cal. Pub. Util. Code, § 454.51(d).
26 Cal. Pub. Util. Code, § 454.52(c).
27 *Id*.
28 *Young v. Haines* (1986) 41 Cal.3d 883, 894; *Coulter v. Pool* (1921) 187 Cal. 181, 185.
29 *Newark Unified School District v. Superior Court* (2015) 245 Cal.App.4th 887, 904.

366.2(f) prevents UOG costs from being included in the PCIA charge because such a conclusion would read part of Public Utilities Code sections 366.2(f) and 365.2 "out of the Law"[30] and "render the statute inconsistent with its own subdivision (g)."[31] The conclusion, however, is incorrect, as the provisions can and must be harmonized. In this case, there is no conflict.

A central objective of statutory construction is to interpret provisions so as to give effect to them all.[32] The Decision errs in finding that the provisions of section 366.2(f) conflict with the prohibitions on cost-shifts in sections 366.3(g) and 365.2. In this case, there need be no conflict because the "cost-shifting" provisions, including those in 366.2(g) and 365.2, are statements of general legislative intent. Sections 366.2(f), 380(b)(2) (regarding RA), 365.1(c)(2)(A) and (c)(2)(C), 454.51(c) (regarding IRP), and 454.52(c) (collectively, DL Charge Statutes) in contrast, detail the *mechanics* for implementing the Legislature's intent. This reading is bolstered by the obvious intent of the relevant provisions. No other reading of the statutory language harmonizes the provisions.

The Decision also errs in finding that holding the list in 366.2(f) as exclusive would read parts of sections 366.2(f) and 365.2 "out of the law."[33] As stated above, there is an obvious reading that harmonizes the two concepts; the general prohibition on cost-shifting is not, in fact, rendered ineffectual by a specific list of costs that may be included in the PCIA as a means of implementing this intent. Indeed, *the reverse is true*: if, as suggested by the Commission, *any* cost may be passed on to CCAs by virtue of the general prohibitions on cost shifting, the specific delineation of costs that may be included in the PCIA set out in 366.2(f) becomes completely ineffectual if that list can be determined entirely at the discretion of the Commission. It is a

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30 D.18-10-019 at 52.
31 *Id.*
32 *Walker v. Superior Court* (1988) 47 Cal.3d 112, 131.
33 D.18-10-019 at 52.

long-standing principle of California law that "courts do not construe statutory provisions 'so as to render them superfluous'."[34] This exact rule against superfluity, relied on in the Decision, would in fact be contravened should the Commission's argument prevail.

The reading proposed by the Decision contravenes another principle it claims to follow: a statute must be interpreted "with reference to the entire scheme of law of which it is part so that the whole may be harmonized and retain effectiveness."[35] The reading of the DL Charge Statutes that harmonizes the provisions and gives effect to them all is the reading the CCA Parties have maintained all along: costs eligible for recovery from CCA departing load are limited to those expressly enumerated by the Legislature.

Ignoring this principle, the Decision claims the CCA Parties' interpretation would "subordinate a later-in-time statute to an earlier-in-time one"[36] and therefore conflict with a principle of statutory construction. Again, the Commission is in error. The cost-shifting language of SB 350 simply does not conflict with the language of 366.2(f). The two provisions can and must be harmonized, as stated above. When read, as is required, to give effect to all provisions, the statutory scheme clearly indicates that SB 350's prohibition on cost shifting is a statement of Legislative intent, easily harmonized with the specific mechanics by which such intent is to be carried out as set forth in the DL Charge Statutes.

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34 *In re J. W.* (2002) 29 Cal. 4th 200, 210 *quoting Shoemaker v. Myers* (1990) 52 Cal.3d 1, 22; *see, also Dyna-Med, Inc. v. Fair Employment & Housing Com*. (1987) 43 Cal.3d 1379, 1397 (Statutes "must be harmonized, both internally and with each other, to the extent possible" *citing California Mfrs. Assn. v. Public Utilities Com.* (1979) 24 Cal.3d 836,844, and interpretive constructions which render some words surplusage are to be avoided.)

35 *Clean Air Constituency v. State Air Resources Board* (1974) 11 Cal.3d 801, 814.

36 D.18-10-019 at 52.

C. Even If Relevant Statutes Could Not Be Harmonized, the Application of Long-Standing Principles of Statutory Interpretation Require the Exclusion of UOG Costs from the PCIA

As noted above, in California "it has long been the rule" that statutes relating to the same subject matter are to be construed together and harmonized if possible.[37] If, however, harmonization is not possible, and an ambiguity remains, courts turn to the rules of statutory interpretation. [38]

The Decision errs in the application of the rules of statutory interpretation that must be applied where multiple interpretations are possible. Under these circumstances, well-established maxims lead to the conclusions that the Legislature intended to exclude UOG costs from the list of costs recoverable from CCA departing load customers. UOG has not been added to this list by the Legislature and it may not be added by the Commission on its own initiative.

1. A General Provision Must Be Subordinated to a More Specific Provision

Even if the specific list in 366.2(f) is viewed as inconsistent with the general language of sections 366.2(g) and 365.2, the rules of statutory construction would require the specific statute to take precedence. In fact, the interpretation of 365.2 is clear if the Legislature has assumed that the Commission implemented 366.2(f) as the Legislature had directed years before—such that Legacy UOG costs are already excluded and the responsibility of other customers or shareholders. Section 1859 of the Code of Civil Procedure codifies a well-established maxim of statutory construction regarding specific provisions that conflict with general provisions: "In the construction of a statute the intention of the Legislature, and in the construction of the instrument the intention of the parties, is to be pursued, if possible; and when a general and particular

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37 *County of Placer v. Aetna Casualty & Surety Co*. (1958) 50 Cal.2d 182, 188-189.

38 *Jauregui v. City of Palmdale* (2014) 226 Cal.App.4th 781, 805.

provision are inconsistent, the latter is paramount to the former. So a particular intent will control a general one that is inconsistent with it."[39] "A specific provision relating to a particular subject will govern in respect to that subject, as against a general provision, although the latter, standing alone, would be broad enough to include the subject to which the more particular provision relates."[40] Thus, even assuming the provisions at issue here could not be reconciled, the specific list of PCIA-eligible costs provided in 366.2(f) must be considered to be a limitation on the Commission's ability to add costs to the PCIA.

2. *Expressio Unius* Leads to the Conclusion That the Legislature's Delineation of Specific Departing Load Charges Was Intended to Be Exclusive

As CalCCA has repeatedly urged, the maxim *expressio unius est exclusio alterius*—the expression of one thing implies the exclusion of others[41]—applies in this case. This maxim requires the Legislature's detailed lists of CCA departing load costs to be interpreted as an exclusive list unless a contrary legislative intent is expressed in the statute.[42] Here, there is no such contradictory legislative intent. On the contrary, and as detailed at length above, the Legislature has repeatedly indicated that additions to the short list of PCIA-eligible costs must be effectuated by specific statutory authorization. Therefore, the absence of language including UOG costs in the statutes authorizing cost recovery from CCA departing load customers must be read as further evidence of the Legislature's intent not to include them.

The Decision errs in failing to observe this maxim and in dispensing with this argument summarily. The Decision cites in a footnote to one case that discusses the *expressio unius*

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[39] Cal. Code Civ. Proc., § 1859.

[40] *People v. Superior Court* (2002) 28 Cal.4th 798, 808, quoting *Miller v. Superior Court* (1999) 21 Cal.4th 883, 895.

[41] *Dyna-Med, Inc. v. Fair Employment & Housing Com.* (1987) 43 Cal.3d 1379.

[42] *Fields v. March Fong Eu* (1976) 18 Cal.3d 322, 332; *CPF Agency Corp. v. Sevel's 24 Hour Towing Service* (2005) 132 Cal.App.4th 1034, 1049.

maxim. The cited case simply holds that the maxim does not apply in the particular circumstances in that case.[43] However, the facts of that case are distinct from the situation at issue here, where the application of *expressio unius* would be appropriate and would lead to the conclusion that UOG should be considered excluded from the DL Charge Statutes.

In *Association of California Ins. Companies v. Jones* the California Supreme Court reviewed the interplay of two provisions in the Unfair Insurance Practices Act.[44] One provision contains a list of specific business practices deemed "unfair claims settlement practices."[45] The other provision of the same statute contains a general prohibition on "[m]aking or disseminating or causing to be made or disseminated . . . any statement . . . with respect to the business of insurance or with respect to any person in the conduct of his or her insurance business, which is untrue, deceptive, or misleading, and which is known, or which by the exercise of reasonable case should be known, to be untrue, deceptive, or misleading."[46]

The Supreme Court agreed that *expressio unius* did not apply. The two provisions actually regulate different activity—one concerns unfair ***settlement practices***, and the other ***statements or representations***. Thus, the existence of a specific list of *practices* deemed unfair does not indicate the intent of the Legislature to exclude any particular type of untrue *statement.* "[T]he fact that the Legislature defined as unfair or deceptive a detailed list of specific unfair claims settlement practices in section 790.03, subdivision (h) . . . does not signal an intent to exempt any particular category of misleading statements from the broad prohibition on such statements in section 790.03, subdivision (b)."[47] In other words, the two statutes at issue address

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[43] *Association of California Ins. Companies v. Jones* (2017) 2 Cal.5th 376, 398.
[44] *Id.* The case concerns the Unfair Insurance Practices Act, Cal. Ins. Code, § 790, *et seq.*
[45] Cal. Ins. Code, § 790.03(h).
[46] Cal. Ins. Code, § 790.03(b).
[47] *Association of California Ins. Companies v. Jones* (2017) 2 Cal.5th 376, 398.

different matters. The Legislature had not specifically defined what statements would be considered misleading or deceptive, so the maxim simply did not apply.

A very different situation is presented here, as the provisions in question address exactly the same matter: departing load charges. Sections 366.2(g) and 365.2 contain general statements prohibiting cost shifts between groups of customers, while the DL Charge Statutes implement this prohibition by providing a mechanism for ensuring cost-shifts do not occur. The costs which could affect a shift in contravention of sections 366.2(g) and 365.2 are those expressly allocated to CCA customers under 366.2(f). In other words, the provisions deal with *exactly* the same costs. The principle of *expressio unius* is designed for precisely this situation and should be applied here.

In fact, the factual situation in the *Jones* case is the converse of that at issue here. In *Jones* the court determined it was not required to expand the Legislature's "specific remedy" for unfair practices. The court found that the Insurance Commissioner could, however, enact regulations concerning misleading statements without adding to the specific remedies provided by the Legislature with respect to unfair practices. In this case, however, there is no way to implement the general prohibition on "cost-shifting" *without* expanding the "specific remedy" provided in the DL Charge Statutes themselves.

The *Jones* decision itself highlights the distinction between the two situations. In *Jones* the Court reiterated that the maxim did not apply to those facts. But the inference to be drawn by the maxim "arises when there is some reason to conclude an omission is the product of intentional design."[48] Unlike the situation in *Jones*, the history of the cost-shifting language at issue here demonstrates intentional design, and that the DL Charge Statutes are intended to be

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48 *Howard Jarvis Taxpayers Assn. v. Padilla* (2016) 62 Cal.4th 486, 514.

exclusive. Thus, *exclusio unius* should be applied to bar expansion of the list of costs that may be passed on to CCA customers through the PCIA.

D. The Decision Errs by Failing to Examine Relevant Policy History Resulting in Unequal Treatment of CCA Customers

Beyond its sparse and flawed statutory analysis, the Decision rejects CalCCA's contention regarding exclusion of UOG costs from the PCIA on policy grounds:

> We cannot find a principled justification to exclude those costs for CCA customers because they are now above-market. Exclusion of those above-market costs amounts to an invitation to shift costs to bundled customers that were incurred to serve CCA customers who later departed.[49]

The Decision disregards an important history associated with UOG resources and ultimately discriminates against CCA customers in the application of its policy.

The PCIA was initially instituted to facilitate the recovery of CDWR power charges from DA customers. Assembly Bill 1X enabled the CDWR to begin to procure resources to serve the utilities' load following the energy crisis, and suspended the rights to enter into DA transactions until the CDWR "no longer supplies power hereunder."[50] In order to recover the CDWR costs from DA customers, the Commission imposed a direct access surcharge or exit fee to recover CDWR costs—the PCIA.[51] However, in imposing these costs on DA customers, the Commission recognized that other resources—UOG resources—were at that time below market.[52] Notably, DA customers explicitly asked the Commission to *include* UOG costs in the PCIA.[53] DA customers did so solely because the lower cost UOG provided a beneficial offset to the newly signed, expensive CDWR contracts. The Commission ultimately agreed with DA

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49 D.18-10-019 at 54.
50 Cal. Water Code, § 80110.
51 D.02-03-055, Finding of Fact 6, at 30.
52 D.02-11-022 at 19.
53 *Id.* at 20.

Customers that the above-market CDWR costs should be offset by including the lower cost UOG in the calculation of the PCIA.[54] There was no "principle" or citation to Legislative directive for this action; it was simply a "deal" approved by the Commission at the time: DA customers received an extension of the Legislature's date for suspension of new DA in exchange for their willingness to pay the netted PCIA.[55] CCAs, of course, were not parties to this agreement, because the first CCA did not begin service until 2010.

The Commission reexamined the issue of including utility generation in departing load charges in D.08-09-012, and again the assumption was made that UOG costs would be lower than the costs of other resources, and therefore would have a mitigating or netting effect on overall departing load charges.[56] This fact was acknowledged by PG&E, which asserted that "departing customers should not receive the benefits of existing generation after they leave bundled service."[57]

While the Commission originally included Legacy UOG in the PCIA to address the interests of DA customers, it extended theses costs unlawfully to departing CCA customers in 2004.[58] Now, however, the utilities have begun or proposed to begin removing UOG costs from the PCIA calculation *solely* for pre-2009 vintage DA customers,[59] and the Decision declines to address this issue. The Commission has permitted pre-2009 DA customers to escape these costs on the

54 *See* D.02-11-022.

55 CalCCA Opening Brief at 33.

56 *See, e.g.*, D.08-09-012 at 49, n.52 ("For purposes of this decision, 'pre-restructuring resources' refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs' retained generation (i.e., hydro, coal and nuclear plants). Power from these resources tends to be cheaper when compared to the costs related to ongoing CTC, the DWR contracts and new generation.").

57 D.08-09-012 at 49.

58 D.04-12-046.

59 Exh. AD-1 at 32; *see also* 3 Tr. 593: 6-594:18 (Fulmer): *see* D.15-12-022, Ordering Paragraph 5.

PG&E system[60] and declined to reject a settlement in the SCE General Rate Case (GRC) that deliver the same benefit to pre-2009 DA customers on its system.[61] The rationale for these actions remains unclear. The Decision states only that "the record in this docket is inadequate to disrupt the status quo for pre-2009 Direct Access customers' treatment under the PCIA," and the issue "will be addressed in A.16-04-018, and not in this proceeding."[62]

The irony, now, is that while these UOG costs originally benefited DA departing load (by reducing the PCIA), the situation is now reversed. Because the relative cost of portfolio assets has now flipped, bearing the cost of this UOG effectively burdens departing load, except today the departing load is from CCA customers. Pre-2009 DA customers received the benefits, and CCA customers receive the burden.

The Decision errs in its duplicity. If failing to include these departing load costs in CCA departing load charges will shift costs to bundled customers, as the Commission concludes,[63] why will the same failure in pre-2009 DA departing load charges have a different effect? The Legacy UOG was in place before either DA or CCA customers began to depart.[64] If the Commission finds that exclusion of Legacy UOG costs in CCA departing load charges results in a cost shift, there is simply no basis for the Commission to conclude otherwise for pre-2009 DA departing load. While the CCA Parties contend that the unequal treatment of pre-2009 DA and CCA customers is unjustifiable, the solution is not to impose these costs on pre-2009 DA customers; under these circumstances, the right solution is to remove Legacy UOG costs from the PCIA for all customers.

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60 D.07-05-005.

61 *See Motion for Approval of Settlement Agreement*, dated February 1, 2018 and filed in the so-called Consolidated ERRA Docket (A.16-04-018, A.16-05-001, and A.16-06-003).

62 D.18-10-019 at 153.

63 D.18-10-019 at 56.

64 "Legacy" UOG is pre-2002 generation that was in place at the time AB 1890 was enacted, and is therefore the subject of Cal. Pub. Util. Code, § 367.

E. UOG Costs Must Be Excluded from Recovery in the PCIA Charged to CCA Departing Load Customers

The Legislature has, since 1996, expressly and specifically defined the costs that may be recovered from departing load by the investor-owned utilities. Most specifically, the Legislature defined a specific subset of utility costs that can and must be included in departing load charges under AB 117. The original list of costs has been expressly supplemented by the Legislature since the statute was passed in 2002. These express lists of recoverable costs are best harmonized with the Legislature's general policy statements regarding cost shifts in SB 350 as the mechanics of implementing its general policy; otherwise, the general statements render the specific lists "surplusage" contrary to established principles of statutory interpretation. Exclusion of UOG Costs is also supported by the history surrounding UOG resources. Moreover, the Commission's contention that the UOG costs must be recovered from all departing load to avoid cost shifts is belied by its actions permitting exclusion of these costs from the pre-2009 DA PCIA.

IV. THE DECISION CAUSES A COST SHIFT BY FAILING TO REDUCE THE NET PCIA PORTFOLIO COSTS BY THE VALUE OF ANY BENEFITS THAT REMAIN WITH BUNDLED SERVICE CUSTOMERS AS REQUIRED BY STATUTE

To prevent cost shifts, departing CCA customers must pay costs specified in subdivisions (d), (e) and (f) of section 366.2.[65] Relevant to this proceeding, subdivision (f)(2) requires such customers to pay:

> the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all

[65] Cal. Pub. Util. Code, § 366.2(c)(5).

> then existing electricity purchase contracts entered into by the electrical corporation.[66]

The directive does not end there. Section 366.2(g) further requires that the costs recovered from CCA customers "be reduced by the v*alue of any benefits that remain with bundled service customers*, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits."[67] Failure to comply with the statute results in a cost shift from bundled customers to departing load customers.[68]

The Decision is devoid of any discussion of this statutory requirement[69] and makes no express findings of fact or conclusions of law regarding its satisfaction of the requirement. On its face, the Decision thus fails to comply with section 1701.2(e), which requires decisions to be "supported by findings of fact on all issues material to the decision…." Section 1701.2(e) also requires that the decision be supported by the record. The CCA Parties contend that the record fails to demonstrate that the adopted benchmark meets the requirement of section 366.2(g). This failure taints both the adopted capacity benchmark, the Decision's rejection of the GHG-free resource premium, and the overlooked ancillary services value.

The Decision thus is contrary to law, fails to provide adequate findings of fact and conclusions of law, and fails to conform to the record in this proceeding.

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66 *Id.* § 366.2(f)(2).
67 *Id.* § 366.2(g) (emphasis added).
68 S*ee* CalCCA Opening Brief at 6.
69 Decision 18-10-019 at 16.

A. The Decision Shifts Costs to Departing Load Customers by Failing to Reduce Net Portfolio Costs to Account for Capacity Costs Remaining in the Bundled Portfolio

1. The Market Price Benchmark Fails to Account for Long-Term Value of Capacity Retained by Bundled Customers

CalCCA provided extensive testimony demonstrating that utility-owned generation and long-term contracts have a long-term value that exceeds the price at which attributes are trading in the short-term market.[70] The Decision observes: "CalCCA's fundamental point is that long-term resources should be valued using long-term valuation measures…."[71] UCAN[72] and POC[73] likewise highlighted the long-term value of resources retained for bundled customers. In fact, the Commission has recognized in several different settings the existence of long-term resource value in the utilities' portfolios.[74] Despite the substantial evidence supporting the existence of long-term value, the Decision rejects CalCCA's long-term valuation proposals, choosing instead to rely on a shallow, unreliable short-term value measure.

By abdicating its obligation to value the capacity that remains with bundled customers, the Decision openly allows a cost shift from bundled to departing load customers. The Decision thus violates 366.2(g), which requires net costs to be reduced by portfolio value, ignores substantial evidence, and is an abuse of the Commission's discretion.

The Decision rejects CalCCA's proposal to recognize the long-term value of capacity based on a failure to "prove" that value:

> We do not dismiss the analysis and contentions of POC and other parties regarding the question of whether the current benchmarks completely capture the long-term value of portfolio resources. At the same time, these parties have had

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70 *See, e.g.,* CalCCA Opening Brief at 42-52, 53-61.
71 D. 18-09-019 at 18.
72 *See* UCAN Opening Brief at 20-23.
73 POC Opening Brief at 6.
74 *Infra* at 23.

difficulty proving that this is the case. We are left to base our decision on what we are able to observe and verify.[75]

In essence, the Commission recognizes the potential that there is a long-term value, but declines to act because it cannot get comfortable with any of the many values CalCCA offered for consideration. The following table shows a range of capacity values estimated by the Commission, the Energy Commission and the CAISO for various proceedings.[76]

Table 2A-3

Comparison to Marginal Cost/Market Values Indicators Across CPUC/CEC Proceedings									
Proceeding	Utility / Region	Model / Source	Capacity $ /kW-Yr	Energy $/MWH	Ancillary Service $/MWH	RPS Cost $/MWH	RPS Premium $/MWH	GHG Value $/tonne	GHG Value $/MWH
PG&E 2018 ERRA	PG&E	ERRA Table 9.5	$58.27	$33.77		$61.47	$24.16		
SCE 2018 ERRA	SCE	ERRA WPs	$58.27	$32.37		$61.47	$25.11		
PG&E 2017 GRC	PG&E	MC/RA WPs	$28.64	$28.30					
SCE 2018 GRC	SCE	MC/RA WPs	$146.85	$36.81					
EE / DRP / LIEE / NEM / DG	North	E3 Avoided Cost Calculator	$113.74	$28.03		$79.90	$14.17	$66.37	$29.15
	South		$109.75	$28.06		$79.90	$14.17	$66.37	$29.15
CEC Title 24	SF CZ 3	2016 TDV Update Model	$145.75	$37.75	$0.19	$126.00	$19.50	$15.72	$9.43
	Fresno CZ 12		$130.54	$37.75	$0.19	$129.90	$19.50	$15.72	$9.43
	LA/SD--CZ 7		$105.70	$38.01	$0.19	$129.90	$19.50	$15.72	$10.31
	LA/SD--CZ 10		$145.58	$38.01	$0.19	$129.90	$19.50	$15.72	$10.31
DCPP Retirement	PG&E	DCPP WPs				$85.62			
CAISO	CAISO	2017 MMC	$74.28	$32.97	$0.54			$12.83	$5.45

Notwithstanding the evidence introduced, instead of adopting a long-term valuation measure the Decision erroneously relies on the annual Energy Division RA Report.[77] The prices reported by the RA Report value the short-term use of a resource to provide RA capacity, which is *not the same product* as the long-term capacity embedded in the portfolio.[78] Moreover, the CCA Parties contend that the RA Report is untested, unreliable and too limited to use as a proxy for the value of 100 percent of the capacity in the utilities' portfolios. The RA Report reflects only a limited scope of products and ignores the value of bilateral contracts, the CAM allocation,

[75] D.18-10-019 at 35-36.
[76] CalCCA Opening Brief at 25 (*citing* Exh. CalCCA-1 at 2A-11-12).
[77] D.18-10-019 at 152.
[78] *See*, CalCCA Reply Brief at 15.

the CAISO CPM and the CAISO RMR mechanisms.[79] In addition, most RA is "procured via long-term PPAs rather than via short-term transactions."[80] Thus, the 2016 RA Report represents only *19.7* percent of 2016 RA—only a fraction of the actual market and of the values inherent in the products sold therein. It is therefore not suitable as a measure of the true value of capacity in the long-term utility resources in the utilities' portfolios.

The Decision's adoption of the RA Report values as a proxy for capacity retained by the utilities is a results-driven abuse of discretion, as evidenced by other Commission statements and actions. The Scoping Memo in this rulemaking recognized the potential for long-term value, requiring that the final methodology must "accurately reflect and seek to preserve all short, medium, and *long-term value of the resources procured by the utilities*…."[81] In addition, the Commission has required the utilities to use long-term values to determine the value of the retained RPS portfolio, *expressly rejecting* the use of short-term prices for this purpose.[82] CalCCA witnesses echoed this conclusion, noting that use of a short-term value for all volumes of a product in the portfolio creates distortions, stating:

> This approach implicitly assumes that the utility could replace all of those long-term volumes in the current market at the then-current short-term price. Alternatively, it assumes the utility could replace all of those long-term products with short-term products and still satisfy the Commission's expectation that the utility will provide customers a secure, reliable supply.[83]

Thus, the Decision contravenes express Commission valuation policies. It is an abuse of discretion for the Commission to, on one hand, require the use of long-term valuation and, on the other, prevent a long-term valuation for the purposes of this proceeding.

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79 Exh. CalCCA-3 2B-3:12-17.
80 *Id.* at 2B-3:17-21.
81 Scoping Memo at 14 (emphasis added).
82 Exh. CalCCA-106, The Padilla Report: Costs and Savings for the Renewables Portfolio Standard in 2016 (May 1, 2017), at 12.
83 Exh. CalCCA-1 at 2B-4:15-2B-5:1.

Perhaps most egregiously, clear evidence demonstrates that the Commission has great depth in portfolio valuation and has regularly estimated long-term attribute values in several proceedings (*see, e.g.,* Table 2A-3 above). For example:

- The Commission has calculated avoided capacity and energy costs under the Public Utility Regulatory Policies Act of 1978 for purposes of pricing the sale of power from Qualifying Facilities to the utilities.[84]

- The Market Price Referent (MPR), a valuation tool used by the Commission in the RPS program, relies on long-term values. The MPR was implemented by the Commission as a result of SB 1078, which first enacted the RPS program.[85]

- In ratemaking, it estimates the marginal cost of various utility functions, including generation capacity. [86]

Most notably, however, the Commission calculates a long-term capacity value for both Northern and Southern California in its Avoided Cost Calculator (ACC)[87] in the Integrated Distributed Energy Resources (IDER) proceeding, R.14-10-003.[88] The purpose of the ACC is to calculate the "costs that the utility would avoid if demand-side resources produce energy in those hours. These avoided costs are the benefits that are used in determining the cost-effectiveness of these resources."[89] In short, it determines the long-term value of capacity. While the long-term capacity values estimated in the IDER proceeding may be used for a different purpose—to support the Commission's climate goals—the ACC estimates the long-term value of the *same capacity product* at issue in this proceeding.[90]

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84 *See, e.g.,* D.10-12-035.
85 *See* Ex. CalCCA-110; Senate Bill 1078 (Stats. 2002, ch. 516).
86 Application 17-06-030, Exh. SCE-04: Rate Design Proposals, filed June 30, 2017 at 96.
87 The avoided cost calculator estimates the costs of the traditional resource, normally a new combination turbine, that will be avoided when a distributed energy resource is procured instead.
88 *See* D.16-06-007.
89 *See* Exh. CalCCA-1 at 2B-7:6-10; *see*, *also* Avoided Cost Calculator User Manual, August 2016, at 1, available through "Avoided Cost User Guide" at http://www.cpuc.ca.gov/General.aspx?id=5267.
90 *See* CalCCA Opening Brief at 49.

Substantial evidence presented by CalCCA and other parties' further reveals the Commission's error. As CalCCA explained: "[u]sing long-term values for planning and the short-term benchmark for the PCIA can create an untenable fiction."[91] Providing an example using RA capacity, CalCCA noted that this fiction "suggests an asset valued at $110/kW-year in the planning process immediately loses value—dropping from $110 to $58—the moment the asset becomes operational and its costs are included in the PCIA-eligible portfolio."[92] Under the Decision, the resource is devalued to $0 if it is not immediately used for compliance or sold in a capacity market. This disconnect— between valuation used to determine if a resource should be procured and valuation used to determine the ongoing value of the resource once it becomes operational—is not rational. The premise that the ongoing value of a resource is $0 is unsustainable. For example, although the resources are to be assigned a $0 value, is it to be supposed that the CCAs could purchase these assets from the utilities for $0 each?

This approach "retains the option value of the assets for bundled customers but requires departing load to pay the cost of bearing the downside price risk for bundled customers without compensation."[93] In other words, departing load customers are paying for benefits of long-term capacity rights that are retained by bundled customers, contrary to the requirement of section 366.2(g).

Other parties agree. The IOUs admit that a short-term approach ignores the other values capacity provides, stating there is no market "to compensate for the full capacity value of post-2002 UOG resources."[94] The testimony of Dr. Woychik, on behalf of UCAN, lends further credence to the need to rely on long-term measures to value long-term resources. He explained

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91 Exh. CalCCA-1 at 2B-7:17-18.
92 *Id.* at 2B-7:18 to 2B-8:1.
93 *Id*. at 2B-5:2-5.
94 Exh. IOU-1 at 5-9:21-23.

that "[t]here is always a price premium paid to reduce long-term uncertainty, which is a major part of the hedge value inherent in bilateral contracts; spot (physical) prices have little if any hedge values, so would systematically understate bilateral contract value." [95] He went on to explain that "[b]ilateral contracts usually represent plant characteristics, which can be used and applied in multiple markets, and accordingly represent option value." He observed that "[s]everal parties, including UCAN, agree that the option value of bilateral contracts should be fully monetized and included." Ms. Kehrein, on behalf of Energy Users Forum, reinforced these observations. She concluded that "to the extent that the current method undervalues utility assets, ignores the value of optionality (hedge value), does not price all components of contract value and results in lost value," the Current Methodology cannot prevent cost shifts between bundled and departing load customers.[96] Indeed, even the Joint Utilities' witness Mr. Wan acknowledged that optionality has value.[97]

Even if, in spite of all of this evidence, the Commission believes the record contains insufficient data for it to "observe and verify" long-term capacity values, it cannot simply wash its hands of a statutory requirement without providing a path forward to eventually meeting it. The Decision complains that there seems to be a lack of "transparent price data" in the record for calculating the benefits of long-term values,[98] but it then offers no clear path in Phase 2 to find that transparency via "voluntary auction frameworks" or other mechanisms.[99] In addition, the Decision's statement that it is "continuing to pursue longer-term solutions that will more

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95 Exh. UCAN-4 at 4.

96 Exh. EUF-1 at 4:5-8.

97 1 Tr. 60:6-22 (Wan).

98 D.18-10-019 at 73-74 (discussing TURN's justification for its proposal for the capacity benchmark, which the Commission adopts stating "we find that TURN's approach to reconciling limited sources of transparent price data and developing as accurate an estimate as possible is credible").

99 *Id.* at 111.

precisely identify and capture the short, medium, and long-term value of utility resources,"[100] indicates that it has not, by definition, already reflected all "long-term value of the resources procured by the utilities." The Decision also fails to provide any guidance for the process now to be undertaken in Phase 2, which process is *required* for an accurate assessment of what values should be included in the current PCIA. For example, the Decision rejects a true-up for RA because "the recorded 'actuals' do not reflect the untransacted capacity used for bundled customer compliance,"[101] but then it does not clearly require parties to work towards a methodology to value holding that capacity for compliance purposes.

Instead, the Commission, in the face of all of its experience and the depth and breadth of testimony supporting long-term valuation, abuses its discretion and violates §366.2(g) in failing to adopt a long-term capacity value to recognize the value remaining in the bundled portfolio.

2. The Market Price Benchmark Understates Portfolio Value by Valuing Capacity Expected to Remain Unsold at Zero

Despite many parties' objections, the Decision concludes that it is "not persuaded that any of the alternatives proposed represent a better capacity benchmark than the RA Report.[102] As the RA Report tracks only capacity prices based on sales in the short term market, unsold capacity will be valued at $0. The Decision is thus in error, as it ignores substantial evidence entered into the record regarding the existence of a value to capacity beyond its short-term value, belying any potential reliance on a $0 value for "unsold" capacity.

The record is replete with testimony demonstrating the existence of long-term capacity beyond what RA may garner in the short-term market, as discussed in Section IV.A.1 above. As CalCCA witnesses noted, long term capacity resources also provide "optionality" value, which

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100 *Id.* at 129.
101 *Id.* at 141.
102 *Id.* at 152.

includes the ability to control and manage these resources, and "hedging" value, which includes the ability to offset price or market risk by entering into offsetting long-term transactions.[103] CalCCA witnesses further testified that determining the value of capacity held in the bundled portfolio using only the short-term RA market price undervalues the asset by as much as a two to one margin.[104] For example, approved long-term planning values for capacity have ranged from $102.31/kW-year in Southern California to $110.93/kW-year in Northern California for purposes of valuing distributed energy resources.[105] However, using values from the RA Report, the current PCIA values this capacity at $37.08/kW-year.[106] The Decision ignores this problem, and then exacerbates it by directing the value of "capacity expected to remain unsold" at $0.

The Commission must ask: if the "unsold" capacity has no value to bundled customers, why is the utility retaining the long-term asset at all? At a zero price, any LSE would be glad to take the assets off the utility's hands. This farcical question encapsulates the Commission's abuse of discretion in ignoring significant and substantial evidence opposing a value of $0 for capacity "expected to remain unsold."

B. The Decision Shifts Costs to Departing Load Customers By Failing to Reduce Net Portfolio Costs to Account for the Value of GHG-Free Resource Benefits Retained by the Bundled Customers

1. The Decision Errs by Concluding that the Evidence Does Not Support the Existence of a GHG-Free Premium

CalCCA proposed the adoption of a proxy to represent the value of GHG-free resources retained in the utilities' portfolios, as the Decision acknowledges.[107] "GHG-free generation carries a premium in today's market, although no reliable published market index values for this

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103 *Id*. at 57.
104 CalCCA Opening Brief at 55; *See* Exh. CalCCA-1 at 2B-4:3-6.
105 CalCCA Opening Brief at 55 (referencing Exh. CalCCA-1 at 2B-4:6-14).
106 2017 Resource Adequacy Report, Table 6, available through http://www.cpuc.cagov/RA.
107 D.18-10-019 at 139.

generation exist."[108] Having recognized the existence of such a premium, however, the Decision rejects CalCCA's proposal:

> CalCCA's position in testimony was that we should administratively apply the RPS adder to all GHG-free generation. This approach is untethered to any reliable, observable market premium. While CalCCA's advocacy on alternative amounts for such an adder has shifted, there remains a paucity of evidence in this proceeding supporting an observable, reliable market premium for this category of energy resources.[109]

The absence of a published index for GHG-free value of a resource does not excuse the Commission from failing to address the record evidence that there ***is*** a separate premium attached to GHG-free resources relative to brown power. Acknowledging the existence of a value and not including it in the PCIA benchmark implicitly acknowledges a cost shift.

CalCCA provided extensive testimony on the existence of a GHG-free premium over brown power. First, the utilities are increasingly focusing their marketing and public relations strategies on GHG-free resources, regardless of whether the GHG-free resources are RPS-eligible.[110] One of the drivers for this value adder, CalCCA's witness testified: "is its marketing value when shown in the LSE's Power Content Label."[111]

Second, PG&E's testimony in the Diablo Canyon Power Plant proceeding likewise validates a premium value for GHG-free resources. PG&E claimed that a "key element" of its proposal was that "it recognizes the value of GHG-free nuclear power as an important bridge over the next eight to nine years."[112] PG&E explained that in filling its Energy Efficiency "tranche" of GHG-free replacement resources, "[o]ffers will not be accepted unless they are

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108 Exh. CalCCA-1 at 2B-10:8-9.
109 D.18-10-019 at 150.
110 CalCCA Opening Brief at 63-64.
111 Exh. CalCCA-1 at 2B-10:9-10.
112 Exh. IOU-118, Chapter 3 at 3-1:19-20.

below a RPS eligible resource cost cap" of $82 kWh in 2016 dollars.[113] As CalCCA's witness explained, "PG&E stated the GHG-free generation from Diablo Canyon was worth considerably more than brown power, amounting to $85/MWh in 2018 dollars."[114]

Third, evidence of GHG-free resource values can be found in the summary of "External Solicitations in Which PG&E Participated (2016-2018)."[115] Of the 17 solicitations PG&E identifies, four sought proposals for "carbon-free" energy separate and apart from other forms of energy. [116]

Fourth, even the utilities acknowledge that other market participants have placed a value on GHG-free energy. The utilities explain how GHG-free transactions "are commonly traded among market participants across the Western Interconnection via voice brokers."[117] Explaining the formula used to calculate the "premium" paid for GHG-free energy versus unspecified energy (*e.g.,* brown power), they conclude that at a GHG allowance price of $14.75/metric ton, "the potential value of GHG-free energy would be $6.14/MWh,"[118] They also cite other indications of a GHG premium, from $2/MWh to $3.50/MWh.[119]

Fifth, California provides a statutory premium for the Joint Utilities for GHG-free power, including that from large hydroelectric resources. Section 454.3 provides for a premium up to a

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113 Exh. IOU-118, Chapter 4 at 4-5:17-21.

114 Exh. CalCCA-1 at 2B-11:3-5 (*citing* PG&E, Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and Recovery of Associated Costs through Proposed Ratemaking Mechanisms, Testimony, A.16-08-006, pp. 4-5).

115 Exh. IOU-3, Table 3-3 at 3-11.

116 *See*, *id.* Table 3-3 at 3-11, Rows 4, 6, 7 and 13.

117 *Id*. at 2-25, n.73.

118 *Id.* Notably, the utilities also acknowledged Sonoma Clean Power and the City of San Diego's estimates of their carbon-free "premium."

119 *Id*. at 2-25:11-15.

full one percent on a utility's rate of return for investment in clean resources, mentioning in particular existing hydroelectric facilities.[120]

Sixth, the premium value has been heightened with the enactment of section 454.53(a), which provides: "It is the policy of the state that eligible renewable energy resources and *zero-carbon resources* supply 100 percent of all retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045."[121]

Finally, the Commission has expressly valued this attribute already, again in the context of the IDER. It thus is entirely aware of the value of avoided GHG emissions, has recognized the value in other contexts, yet the Decision fails to address it because it does not find an observable, reliable market premium for this category of energy resources.[122]

Even opponents to the GHG-free premium implicitly or explicitly recognize the value of these resources above the brown power value. TURN acknowledged the potential GHG-free premium:

> offering a supply of PCC 1 renewable energy, GHG-free hydroelectric power and long-term renewable energy sales would provide valuable products that may command premiums over the day-ahead CAISO markets currently used as the primary basis for benchmarking the net costs of such resources.[123]

While CLECA opposed the GHG-free adder, its opposition targets the values identified by CalCCA, not the existence of a GHG-free premium.[124]

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120 § 454.3(a) provides for a return premium for investment in a facility "designed to generate electricity from a renewable resource, including, but not limited to, solar energy, geothermal steam, wind, and hydroelectric power at new or existing dams…."

121 Senate Bill 100 (Stats. 2017-2018, ch. 312, § 454.53(a)) (emphasis added).

122 D.18-10-019 at 150.

123 TURN Opening Brief at 27.

124 *See* CLECA Opening Brief at 10-11.

The evidence presented in this proceeding makes clear that there is a GHG-free value embedded in the utilities' portfolios. The Commission, on one hand, recognizes long-term values for GHG avoidance when it wants to promote a technology, yet on the other pretends it does not exist in calculating the PCIA, where it suits the purpose of reducing bundled customer costs. There could be no clearer abuse of discretion than the Commission's results-driven rejection of a GHG-premium to value the utilities' portfolios.

2. The Decision Errs by Concluding that Any GHG-Free Premium Will Be Captured in the Brown-Energy True-Up

The Decision erroneously concludes that "[a] market premium attributable to GHG-free resources, to the extent it exists, will be captured in our true-up…."[125] The Decision provides no record support for this conclusion[126] other than a very loosely related statement by the Joint Utilities:

> [d]ispatched GHG-free resources command the same market-clearing prices as all other resources, but do not have a corresponding GHG compliance cost. Accordingly, the delta between their costs and awarded revenues is larger than a fossil resource. . . . This value is already pro-ratably shared with departing load customers, as it is captured in the PCIA's 'brown' MPB when trued-up for actual market revenues.[127]

As CalCCA expressed several times during the proceeding, by suggesting that GHG-free value is somehow worked out in the brown power market, the Joint Utilities' argument equates the value of brown power with the value of GHG-free resources.[128] In the face of Senate Bill 100, it is patently obvious that the state values GHG-free or zero-emissions resources more than it values natural gas or other emitting resources. In fact, the Commission itself regularly calculates a

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125 D.18-10-019 at 150.

126 The Decision's footnote refers to CalCCA's Reply Comments on the true-up, which do not address the valuation of GHG-free resources in the utilities' portfolios. *See, id.* fn. 317.

127 D.18-10-019 at 150 (citing Joint Utilities Reply Comments at 5 and TURN Reply Brief at 18).

128 CalCCA Opening Brief at 66.

GHG-free value—apart from the value of brown power—in the IDER for purposes of estimating the value of energy efficiency.[129]

The Commission errs in suggesting that the brown power price captures GHG-free value.

C. The Decision Shifts Costs to Departing Load Customers By Failing to Reduce Net Portfolio Costs to Account for the Value of Ancillary Services

CalCCA proposed adoption of a benchmark to account for ancillary service value in the bundled portfolio, which the Decision acknowledges.[130] Although the Decision recites the views of CalCCA and other parties on this proposal,[131] it fails entirely to make findings or draw any conclusions regarding the need for an ancillary service benchmark. On its face, the Decision thus fails to comply with section 1701.2(e), which requires decisions to be "supported by findings of fact on all issues material to the decision…."

V. THE DECISION VIOLATES §366.2(F)(2) BECAUSE IT CAUSES A COST SHIFT BY INCLUDING COSTS IN THE PCIA THAT ARE NOT "ATTRIBUTABLE" OR "UNAVOIDABLE" TO DEPARTING LOAD CUSTOMERS

Public Utilities Code section 366.2(f)(2) permits the recovery of relevant costs from a CCA departing load customer only if those costs are "unavoidable" and they are "attributable" to the customers. The Scoping Memo, partly recognizing its obligation, adopted Guiding Principle 1.h., which provides that PCIA charges "should only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above market costs…."[132] Despite these statutory requirements, the

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[129] Exh. CalCCA-1 at 2B-10:11-19.

[130] *See* D.18-10-019 at 19.

[131] *See, e.g.,* D.18-10-019 at 16 (Joint Utilities' GAM), 67-70 (Shell), 71-72 (UCAN), 23 (TURN). The Decision also mentions ancillary services generally in establishing the Portfolio Allocation Balancing Account (PABA). *Id.* at Ordering ¶ 7 at 161.

[132] D.18-10-019 at 106 (citing Scoping Memo Guiding Principles).

Decision fails to draw any meaningful conclusions regarding whether the costs recovered in the PCIA are actually "unavoidable" and "attributable" to departing load customers.

The only conclusion regarding the Decision's compliance with this Guiding Principle lacks any detail or substance:

> We find that this principle is satisfied because we have acted in this proceeding to determine with unprecedented precision the nature of the costs incurred by the Joint Utilities, and we are initiating a second phase of this rulemaking that offers the promise of meaningful progress toward reducing the levels of above-market costs going forward.[133]

Section 366.2(f)(2) does not direct the Commission to "determine the nature of costs" recovered through the PCIA. Instead, it requires the Commission to assess whether the costs imposed on departing load are actually "unavoidable" and "attributable" to those customers. The Commission has made no effort to make findings of fact or draw conclusions of law regarding these statutory requirements, let alone determine whether the particular costs recovered through the PCIA meet these requirements.

In failing to undertake these assessments, the Commission has failed to comply with governing law and has proceeded without substantial evidence.

A. The Decision Errs by Continuing to Include in the PCIA the Costs of Ongoing Capital Additions in UOG That Are Not "Attributable" to Departing Load Customers

The PCIA recovers all UOG-related costs of keeping UOG resources available, "including fixed O&M, capital additions, ad valorem and insurance costs."[134] The CCA Parties contend that capital additions costs for UOG resources incurred *after* a load departs are not "attributable" to the departing load and, instead, represent a benefit to bundled customers.[135]

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133 *Id.* at 129.
134 Exh. CalCCA-1 at 2B-16:13-15.
135 D.18-10-019 at 134-135. *See* Exh. CalCCA-1 at 2B:16-19.

CalCCA supported this contention through extensive testimony about the value of utility plants.[136] The Decision summarily concludes:

> CalCCA's concern about ongoing costs for legacy UOG has potential merit, but lacks sufficient record support or an adequately developed test for evaluating such costs. It is possible that new investments in an old power plant may represent such a significant overhaul of the facility as to justify a "re-vintaging" of the facility. Likewise, it is possible that plant investments for certain upgrades may justify a different vintage treatment for those investments than for the underlying facility. But any such analysis must be fact-specific to the plants and spending in question, and is better suited to a GRC evaluating such spending. CalCCA's testimony and argument on this subject in this proceeding did not meet its burden of persuasion.[137]

The Decision thus implicitly acknowledges that the PCIA may include costs that are not attributable to departing load customers, but fails to act.

The Commission abused its discretion by failing to address this issue, despite the substantial evidence presented by CalCCA, while knowing it could be causing a cost shift from bundled to departing load customers.[138] Moreover, rejecting the proposal because CalCCA has not "adequately developed [a] test for evaluating such costs,"[139] departs from the Commission's approach on other issues. The Decision draws numerous policy conclusions that require implementation, but leaves the details to be developed in another phase. For example, the Decision adopts a framework for a PCIA prepayment option that would be made available to departing load customers, but specifies that the detail of the option—which it identifies in its Ordering Paragraph—for resolution in Phase 2.[140] The record certainly had sufficient evidence to demonstrate that the utilities incur ongoing costs for their UOG and that the costs may be

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136 *See, e.g.*, Exh. CalCCA-1 at 2B-16-2B-19; Exh. CalCCA-3 at 2B-6-2B-8 and Table 2B-1.
137 D.18-10-019 at 135.
138 Exh. CalCCA -1at 2A-12 -2A-17, Fig. 2A-2 at 2A-15, and Fig. 2A-4 at 2A-16.
139 D.18-10-019 at 135.
140 D.18-10-019, Ordering ¶11.

uneconomic and not attributable to departing load customers.[141] The Decision thus could have directed that any costs of ongoing capital investment in UOG incurred after a customer's departure would not be placed in that customer's vintage, with Phase 2 limited to directing development of a "test."

The Commission abused its discretion in failing to adopt a policy regarding ongoing UOG capital additions, thus retaining those costs in the PCIA for customers who departed before the costs were incurred. The failure inures to the benefit of bundled customers by keeping ongoing capital investment costs in the PCIA and thus shifts costs from bundled to departing load customers.

B. The Decision Errs by Permitting Recovery of Avoidable Shareholder Returns on UOG from Departing Load Customers

CalCCA presented extensive testimony proposing UOG securitization as a means of "refinancing" UOG and thus reducing the costs paid by customers.[142] Through the use of securitization, CalCCA contended, UOG costs could be "avoided." The Decision, however, fails to direct the utilities to pursue securitization. Because section 366.2(f)(2) permits allocation of only those costs that are "unavoidable," the costs that could have been avoided—a portion of the utility's UOG return on equity—cannot be recovered through the PCIA. For this reason, the Commission erred in including the returns on UOG assets in the PCIA-eligible costs allocated to CCAs.

CalCCA's testimony explained that "[p]roceeds from the sale of securitized bonds provide a source of capital that can be used by the utilities at a much lower cost than typical

141 Exh. CalCCA-1 at 2B-21, Table 2B-1; Exh. CalCCA-3 at 7-13:13-16 and Exhibit 7-A; CalCCA Opening Brief at 102.

142 *See, generally* CalCCA-1, Vol.2, §III and Exhibits 3-A through 3-D.

utility financing."[143] CalCCA proposed to raise capital through a bond issuance "sufficient to repay the utilities for their remaining investment in their generation facilities, the generation rate base: approximately $4.2 billion for PG&E and $1.5 billion for SCE."[144] The testimony explained that the benefits of this proposal have a net present value of $1.3 billion for PG&E and $589 million for SCE.[145] Other parties either supported this proposal or agreed that it merits consideration.[146]

Despite this substantial evidence, the Commission declines to direct the utilities to reduce their portfolio costs through securitization.[147] It concludes, without record evidence or a full discussion of its analysis:

> [W]e are cautious about the feasibility of this strategy given recently adopted legislation regarding the securitization of wildfire liability costs. [Citation.][148] It is unclear how additional utility securitizations would interact, and what implications there would be for overall utility borrowing costs. Given those uncertainties, we direct parties to focus on the abovementioned issues first.

By rejecting CalCCA's proposal to "avoid" ongoing returns on generation rate base, CCAs and ESPs – and their customers – will continue to be forced to pay the return on their competitors' investment.

The Commission should grant rehearing on this issue and modify the Decision to adopt the general principle that shareholder returns are neither attributable to nor recoverable from departing load customers through the PCIA. It may, as it did with other issues, defer the implementation mechanics to Phase 2.

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143 *Id*. at 3-6: 5-6.
144 *Id.* at 3-6: 14-16.
145 *Id.* at 3-7: 7; *see also, id.*, Exhibit 3-A.
146 *See* D.18-10-019 at 107-110.
147 *Id.* at 114.
148 The Commission cited SB 901.

C. The Decision Errs by Failing to Determine Whether the Costs Recovered through the PCIA are "Unavoidable" and "Attributable" to CCA Departing Load Customers

1. The Costs of Post-2002 UOG Costs, Which the Commission Explicitly Directed the Utilities to Manage Within a 10-year PCIA Recovery Period, Could Have Been Avoided and Should Not Be Recovered from Departing Load Customers

The Decision errs by expanding the PCIA to permit recovery of post-2002 UOG costs despite the Commission's repeated directive to the utilities to manage these resources to avoid stranded costs. The Decision expands the PCIA by lifting the existing 10-year limit on the recovery of post-2002 UOG fossil costs without a reasonable justification.[149] This expansion removes an obligation placed previously on the utilities to manage their portfolios to prevent excess procurement and thus allows recovery of "avoidable" costs from departing load customers contrary to section 366.2(f).

The Commission first adopted the 10-year limit in 2003 in approving SCE's Mountainview Generating Station, based on a proposal offered by TURN.[150] Mountainview was presented as a "unique opportunity" by SCE, but opposed by ORA and TURN as a "unique burden."[151] TURN argued that "if Mountainview, Mohave, and direct access all converged simultaneously it could place bundled customers at serious risk of 'rate shock.'" ORA further argued that Mountainview would be "too costly to ratepayers since it will come on line before it is needed and will contribute to an oversupply of capacity." The Commission adopted TURN's proposal to require departing load customers to pay the costs of these resources for 10 years so that "ratepayers are not overburdened during the early years of the contract with stranded costs if

149 D.18-10-019, Conclusion of Law 13.
150 D.03-12-059 at 35 and Finding of Fact 22 at 63.
151 *Id.* at 32.

all the power is not needed…" The Commission's decision did not authorize SCE to reopen cost allocation of this resource in later years.

The Commission applied this limitation more generally in its 2004 adoption of the utilities' Long-Term Procurement Plans, extending it prospectively to all "fossil-fueled resources acquired by the utilities either directly or through contract."[152] It made clear that the limitation would apply to "utility-owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation." [153] In the next paragraph, the Commission contemplated greater flexibility for commitments under PPAs. It stated:

> As several parties have noted, limiting commitments for new resources to only ten years may still increase costs for captive ratepayers due to the need for the project developer to seek accelerated cost recovery for their investments rather than amortizing these investments over a longer time period.[154]

In describing these circumstances, the Commission said that it would "allow the utilities the opportunity to justify in their applications, on a case-by-case basis, the desirability of adopting a cost recovery period of longer than ten years." At the same time, it made clear that a longer term stranded cost recovery would apply to renewable resources.[155]

The Commission confirmed its position once again in 2008, retaining the 10-year limitation. The Commission explained:

> [T]he utilities can, over time, adjust their load forecasts and resource portfolios to mitigate the effects of DA, CCA, and any large municipalizations on bundled service customer indifference. By the end of the 10-year period, we assume the IOUs would be able to make substantial progress in eliminating such effects for customers who cease taking bundled service during that period.[156]

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152 D.04-12-048 at 61.
153 *Id.*
154 *Id.*
155 *Id.*
156 D.08-09-012 at 54-55 (emphasis added).

It further observed that the resources also may become more economic over time, suggesting that it would be to the ratepayers' benefit to hold those resources to lower total portfolio costs at a later date. It provided, however, that if the utilities "believe a cost recovery period extension is appropriate and necessary for <u>specific</u> non-RPS resources, they can make such requests…."[157]

In rejecting the proposals of CalCCA and other intervenors to maintain the 10-year limitation, in the face of the Commission's own prior decisions, Decision 18-10-019 misses the mark. The Decision:

- Reverses the burden of proof. Rather than requiring the utilities to make a showing to lift the limitation, the Decision concludes that the non-utility parties have the burden of proof: "[t]he parties opposing the termination of the 10-year limit have demonstrated no factual, legal, or technical error in their comments on the subject."[158]

- Rewards the utilities by releasing them from their existing obligations because to do otherwise would "simply place the burden of cost recovery on bundled customers after the 10-year limit expires."[159]

- Focuses on PG&E's Humboldt plant—a local reliability asset for which another solution to cost recovery can be found.[160]

It thus fails entirely to examine whether these costs are "unavoidable" and attributable." And while the Decision punts the issue to Phase 2, where the Commission will generally undertake "portfolio optimization,"[161] it once again provides no direction regarding examination of the utilities' conduct with respect to this issue.

The Commission addressed the 10-year limitation as a zero sum game, which it is not. Had the Commission set the scope of the proceeding to allow a review of the utility's prior actions with respect to portfolio management, the issue would not be a zero sum game between

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157 *Id.* at 55 (emphasis added).
158 D.18-10-019 at 136.
159 *Id.* at 56.
160 *Id.* at 59.
161 *Id.* at 61.

bundled and departing load customers. The Commission thus erred in its failure to determine whether these or any other costs incurred were avoidable.

2. The Utilities' Failure to Manage Their Portfolios in Response to Departing Load Resulted in "Avoidable" Procurement That Cannot Be "Attributed" to CCA Departing Load

The Commission and the utilities have long been aware of the need to consider and forecast departing load in developing and implementing procurement. Notwithstanding this awareness—or, perhaps, because of such awareness—the utilities have, from the outset of CCA formation, continued to procure on behalf of CCA customers until the last possible moment such customers remain with bundled service, even when the utilities know or should have known that such customers were soon departing. The result is costs that could have been avoided and that cannot be attributed to CCA departing load.

Forecasting has been central to procurement since the energy crisis. In D.03-04-030, the Commission established an exemption from the CDWR Power Charge based on CDWR's forecast of departing load. It stated:

> It is clear that DWR, when negotiating long-term power contracts, assumed that a certain amount of customer generation departing load would occur every year and therefore did not procure long-term power for that portion of the load. ***In fact, such an assumption is based on common sense, since utilities have always faced departing load in various forms, including that caused by an economic downturn, improvements in energy efficiency and building codes, as well as installation of self-generation systems***.[162]

The Commission drew two important conclusions in this decision: first, that forecasting departing load makes "common sense," and second, if a procurement plan indicates a load departure, the departing load should be exempt from resources procured in implementing that plan.

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[162] D.03-04-030 at 54 (emphasis added).

From the outset, the utilities refused to recognize the departures of CCA customers absent near certainty that a particular load would depart.[163] The result is that the utilities are overprocured,[164] even though these costs could have been avoided. Compounding the error, the utilities acknowledged that they would not have altered their procurement strategy *even if they had known of the departure*.[165] In PG&E's opinion, a reasonable portfolio manager would not have made any procurement decisions based on the potential departure of a small level of load.[166] In fact, to have any impact, PG&E concluded that the departure would need to be in the neighborhood of 10-20 percent of its load.[167] Given PG&E's admission that its procurement would not be altered until it felt that 10-20 percent of its load was imminent, the earliest CCA customers were saddled with procurement costs that could have been avoided in the first place. And also as clearly, any avoidable overprocurement that resulted cannot be considered attributable to the departing load.

The CCA Parties acknowledge that the Assigned Commissioner established a scope for the proceeding that excluded revising specific prior Commission determinations regarding the reasonableness of the IOUs' past procurement actions.[168] However, this exclusion of reconsidering *particular* past actions does not preclude a review of these same past actions to determine in this proceeding when a cost is not "unavoidable" or

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163 *See* 4 Tr. 809:20-810:3 (Cushnie); 4 Tr. 813:9-10 (Lawlor); 4 Tr. 814:13-16 (Lawlor).

164 CalCCA Opening Brief at 87.

165 Mr. Lawlor stated that "Marin as a percentage of PG&E's total load was between 0.1 percent and 0.2 percent" in 2010. *See*, 5 Tr. 853:25-854:1 (Lawlor) (in describing PG&E's decision to retain Marin in its procurement strategy).

166 5 Tr. 855:5-9 (Lawlor).

167 1 Tr. 37:17-21 (Wan).

168 *See* Scoping Memo at 19 ("As made clear at the PHC, and reiterated here, the scope of this proceeding will not include revisiting prior Commission determinations regarding the reasonableness of the IOUs' past procurement actions.").

"attributable" to departing load customers.[169] In fact, by failing to enforce the mandates of the Procurement Policy Manual[170] in this proceeding, and in failing to ensure that the utilities prudently managed their generation portfolios and took all reasonable steps to minimize above-market costs for all ratepayers, the Commission has failed to meet its statutory requirements under sections 280, 454.5, and 399.11-399.20 and thus ensure that only avoidable costs are included in the PCIA under 366.2(f)(2).

Moreover, even when presented with evidence demonstrating that the utilities' have not taken the actions required to avoid any "avoidable" costs, the Commission has failed to act. To correct its error, the Commission must (1) find that a utility's failure to reasonably forecast departing load and to take direct action in response to this forecast departing load results in "avoidable" costs that cannot be recovered from departing load customers and (2) reverse its decision to lift the 10-year limit on post-2002 UOG cost recovery through the PCIA. At a bare minimum, the Commission must permit a subsequent examination of the compliance of the PCIA-eligible costs with the requirements of section 366.2(f)(2).

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169 While CalCCA adhered to the Scoping Memo's directive, it did, however, provide a clear record on utility actions with respect to Marin Clean Energy (MCE) demonstrating that certain procurement activity in 2010 was not attributable to MCE's departing load customers. *See* CalCCA Opening Brief at 99-101.

170 The Procurement Policy Manual was adopted by Scoping Ruling filed on June 2, 2010 in Rulemaking 10-05-006, and is available at: http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/118826.PDF

VI. CONCLUSION

For all of the foregoing reasons, the CCA Parties request that the Commission grant rehearing of D.18-10-019 on the issues identified in this Application.

Respectfully submitted,

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November 19, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

APPLICATION FOR REHEARING OF PENINSULA CLEAN ENERGY AUTHORITY, MARIN CLEAN ENERGY, AND SONOMA CLEAN POWER AUTHORITY OF DECISION 18-10-019

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

APPLICATION FOR REHEARING OF PENINSULA CLEAN ENERGY AUTHORITY, MARIN CLEAN ENERGY, AND SONOMA CLEAN POWER AUTHORITY OF DECISION 18-10-019

Pursuant to Public Utilities Code section 1731(b)(1) [1] and Rule 16.1 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Peninsula Clean Energy Authority ("PCE"), Marin Clean Energy ("MCE"), and Sonoma Clean Power Authority ("SCP") respectfully submit this Application for Rehearing of Decision 18-10-019 ("PCIA Decision") issued on October 19, 2018. Section 1731(b) requires that an application for rehearing be filed no later than 30 days after the date of issuance of the decision for which rehearing is sought. This application for rehearing is timely filed.

The Commission fails to meet its statutory duty to set the Power Charge Indifference Adjustment ("PCIA") based on a factual and legal determination that the investor-owned utilities ("IOUs") incurred legitimately unavoidable costs and took all reasonable steps to minimize above-market costs. Furthermore, the PCIA decision fails to meet the requirements of Sections 365.2 and 366.2(f)(2) by attributing costs to the earliest CCA departing load customers (including those served by PCE, MCE, and SCP) that Pacific Gas and Electric Company

[1] All subsequent statutory references are to the Public Utilities Code.

("PG&E") admits were not incurred on behalf of that departing load. For these reasons, the Commission should grant this Application for Rehearing. In addition, PCE, MCE, and SCP join and support the Application for Rehearing advanced by the California Community Choice Association ("CalCCA"). The Commission should also grant rehearing on the grounds described in CalCCA's application.

I. THE COMMISSION FAILS TO MEET ITS STATUTORY DUTY TO SET THE NEW PCIA BASED ON A FACTUAL AND LEGAL DETERMINATION THAT THE IOUs INCURRED LEGITIMATELY UNAVOIDABLE COSTS AND TOOK ALL REASONABLE STEPS TO MINIMIZE ABOVE-MARKET COSTS

The Commission appropriately acknowledged that "any PCIA methodology adopted by the Commission to prevent cost increases for either bundled or departing load" should, among other things, "only include legitimately unavoidable costs and account for the [investor-owned utilities' ('IOUs')] responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs."[2] Yet the final PCIA Decision establishes a new PCIA with no legal or factual determination that the utilities incurred legitimately unavoidable costs and took all reasonable steps to minimize above-market costs. The Commission's failure constitutes an abuse of discretion and fails to ensure (i) that the IOUs meet the mandates of the Procurement Policy Manual, which confirms and implements the IOUs' duty to mitigate its losses and "provides all of the requirements and guidance provided by the Commission to its jurisdiction entities under [Sections] 380, 454.5, and 399.11-399.20,"[3] and (ii) ratepayer indifference established in Section 366.2(f)(2).

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[2] D.18-10-019 at 106 (citing Scoping Memo Guiding Principles).
[3] The Procurement Policy Manual was adopted by Scoping Ruling filed on June 2, 2010 in Rulemaking 10-05-006, and is available at: http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/118826.PDF.

The PCIA Decision includes an unsubstantiated "finding" in dicta that:

> this principle is satisfied because we have acted in this proceeding to determine with unprecedented precision the nature of the costs incurred by the Joint Utilities, and we are initiating a second phase of this rulemaking that offers the promise of meaningful progress toward reducing the levels of above-market costs going forward.[4]

However, this "finding" is unsupported by substantial evidence. More importantly, the PCIA Decision itself cites to no evidence, establishes no findings of fact, nor draws any conclusions of law necessary to meet its statutory responsibility to ensure that the IOUs incurred legitimately unavoidable costs and took all reasonable steps to minimize above-market costs.

Thus, the Commission must act to either:

1) address whether the IOUs incurred unavoidable costs and took all reasonable steps to minimize above-market costs *before* establishing a new PCIA; or,
2) at the very least, ensure that parties may further continue in Phase 2 of this proceeding to identify the extent to which the costs incurred by the IOUs to date are illegitimate and avoidable.

In either scenario and to comply with its statutory responsibility, the Commission must remediate the avoidable costs it determines the IOUs incurred to both reduce above-market costs going forward and decrease the costs that ALL ratepayers must pay, both bundled and unbundled.[5]

A. By Failing to Enforce the Mandates of the Procurement Policy Manual, the Commission's Decision Fails to Meet Statutory Requirements

To comply with Section 366.2(f)(2), the Commission established Guiding Principle 1.h in the Scoping Memo for this proceeding and concluded that only unavoidable costs should be included in the PCIA. However, the Commission failed to fulfill this requirement by ignoring

[4] D.18-10-019 at 129 (citing Scoping Memo Guiding Principles).
[5] The Commission can conduct this exploration for the benefit of this proceeding and setting the new PCIA rate without re-litigating or reopening any specific past determinations, as expressly required in the Scoping Memo's directive in this proceeding that "the scope of this proceeding will not include revisiting prior Commission determinations regarding the reasonableness of the IOUs' past procurement actions." *See* September 25, 2017 *Scoping Memo and Ruling of Assigned Commissioner* at 19.

the statutory mandates that support the Procurement Policy Manual. Consequently, the Commission failed to ensure that the IOUs prudently managed their generation portfolios and took all reasonable steps to minimize above-market costs for all ratepayers. As such, the Commission has failed to meet its duties pursuant to Sections 380, 454.5, and 399.11-399.20 and ensure that only unavoidable costs are included in the PCIA under Section 366.2(f)(2).

1. Standard of Conduct #4 Implements and Confirms the Statutory Requirements for Prudent Management of a Utility's Generation Portfolio and an IOUs' Duty to Mitigate

The Procurement Policy Manual sets standards for prudent management of a utility's generation portfolio. Standard of Conduct #4 requires that:

> In administering contracts, the utilities have the responsibility to dispose of economic long power and purchase economic short power in a manner that minimizes ratepayer costs. Once a contract has been deemed compliant with the utilities' procurement plan, the contract is not subject to reasonableness review. However, the administration of the contract by the utility remains subject to a reasonableness review and disallowance through ERRA proceedings.

Thus, the IOUs have an obligation to prudently manage their generation portfolio, and the Commission must vigilantly review the IOUs' management practices particularly regarding utility-owned generation ("UOG") where the utility's inherent financial incentive is to increase capital costs in its rate base. Despite longstanding requirements that the utilities forecast load and adjust their activities to mitigate impacts on bundled customers over time from their UOG, the IOUs have only in the last few years made strides to improve their departing load forecasting.

Furthermore, Standard of Conduct #4 incorporates the broader duty of a party to mitigate its losses. A damaged party may not simply sit back and do nothing, if doing so will increase its loss. The damaged party is under a legal duty to mitigate – to avoid – its losses. This mitigation requirement particularly applies to situations in which a party has an economic incentive to sit back and take no action, transferring all risk of market changes to its competitors. Failure to enforce this legal duty permits the party to reduce or eliminate competition. To avoid this unfair practice, the law requires such a party to mitigate its damages by promptly re-contracting with a third party for the sale of the goods. If the party fails to do so, it can recover no damages or losses it could have reasonably avoided.[6]

2. The Record Confirms that the IOUs Have Failed to Avoid Over-Procurement and Minimize Portfolio Costs

The original Proposed Decision of Administrative Law Judge ("ALJ") Roscow emphasized that "[t]he record in this proceeding **clearly** demonstrates that… the Joint Utilities have not made a convincing showing regarding **what actions, *__if any__*,** they have taken since 2004 to comply with the Commission directives …."[7] This proceeding's record is replete with evidence that the IOUs failed to avoid over-procurement and minimize portfolio costs and meet their broader duty to mitigate, particularly in the face of increasing departing load.

For example, after confirming that PG&E was long in resource adequacy, energy, and RPS supply, PG&E Witness Wan admitted that PG&E failed to avoid over-procurement. Witness Wan stated that PG&E has sold none of its long-term RPS contracts in the market, nor is there any plan to do so in the joint IOUs' proposal, despite years of increasing departing load.[8] Similarly, during cross examination ALJ Roscow questioned why PG&E sold no products until

[6] "A party injured by a breach of contract is required to do everything reasonably possible to negate his own loss and thus reduce the damages for which the other party has become liable. The plaintiff cannot recover for harm he could have foreseen and avoided by such reasonable efforts and without undue expense. However, the injured party is not precluded from recovery to the extent that he has made reasonable but unsuccessful efforts to avoid loss." (*Brandon & Tibbs v. George Kevorkian Accountancy Corp.* (1990) 226 Cal.App.3d 442, 460, internal citations omitted.); *see also* D.08-09-012 at 54 (utilities were expected to manage their generation portfolio to mitigate loses due to the ten year limitation);
[7] August 1, 2018 *Proposed Decision of ALJ Roscow Modifying the Power Charge Indifference Adjustment Methodology* (R.17-06-026) at 62 (emphasis added).
[8] 1 Tr. 38:7-39:13 (Wan).

2018 when it first noticed a long position in 2014 and knew that MCE departed in 2010. ALJ Roscow remarked regarding PG&E's failure to avoid over-procurement:

> [I]sn't it in kind of all parties' and all ratepayers' self-interest to ensure that double procurement doesn't happen? ... So why would you say that in your original proposal there's no plan to provide a bundled product that would include the [Renewable Energy Certificates ("RECs")] that I assume would be most attractive to the departing load? It seems like you're holding back the RECs for some reason?[9]

ALJ Roscow thus ascertained that either PG&E benefits from holding unneeded RECs or PG&E improperly failed to act in accordance with statute and Commission policy. Either scenario violates the principles of indifference and prudent portfolio management.

Similarly, as evidence of SCE's failures to prudently manage its portfolio, SCE Witness Cushnie admitted that "Edison has a single resource, I believe, that is post-2002. And that's the Mountain View generating station. And I haven't looked at its revenue requirement versus market revenues in a long time. So I don't know if it's ever had a net positive under your question."[10]

Finally, evidence of SDG&E's similar failures are also in the record. For example, in response to the question of whether the utilities have submitted any necessary applications to justify cost recovery of longer than the ten year limit (which would have provided evidence that SDG&E was prudently managing its portfolio), Witness Shults stated "as for SDG&E, we have not submitted such an application."[11]

The PCIA Decision ignores this record evidence that the IOUs failed to meet statutory requirements and take reasonable actions to manage their portfolios. Compounding this error is

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[9] 1 Tr. 76:1-24; 80: 22-81:4.
[10] 2 Tr. 338: 13-19 (Cushnie).
[11] 3 Tr. 436: 16-437:16 (Shults).

that the final PCIA Decision excises out ALJ Roscow's conclusion that the IOUs have not complied with prior Commission directives. The result is a PCIA Decision that improperly and unlawfully includes avoidable costs in the new PCIA.

3. The Existence of the ERRA Proceeding and Other Regulatory Venues to Evaluate Utility Prudence Does Not Relieve the Commission of Its Statutory Duties In This Proceeding

The Commission has a duty to ensure that "departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[12] Furthermore, the Commission must ensure that all rates and charges collected by a public utility are "just and reasonable," including the PCIA, and a public utility may change no rate "except upon a showing before the [C]ommission and a finding by the [C]ommission that the new rate is justified."[13]

The Commission may have allowed costs in previous proceedings[14] it may now determine to be avoidable. The Commission's actions in past proceedings do not preclude it from safeguarding all ratepayer interests now, both bundled and unbundled, having conducted in this proceeding, "with unprecedented precision," the most thorough accounting of IOU costs to date.[15] In evaluating the IOUs' actions regarding portfolio management and avoidance of above-market costs to set a new PCIA, if the Commission finds that the utilities acted improperly or that more review is warranted, then the Commission must not ignore the record, should hold the utilities accountable for their past mismanagement to the benefit of all ratepayers, and set the new PCIA excluding avoidable costs.

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[12] *See* Pub. Util. Code § 365.2.
[13] *See* Pub. Util. Code §§ 451, 454.
[14] There is no need to relitigate those previous proceedings and contravene the Scoping Memo's prohibition against doing so.
[15] D.18-10-019 at 129.

Furthermore, the Commission has drastically limited the scope of the ERRA proceeding, which has dismantled the Commission's evaluation of prudence in IOU portfolio management to the point where the Commission has failed its statutory responsibilities in this regard. The following recent history of PG&E's ERRA process showcases the inability for CCAs and other stakeholders to find a venue to address billions of dollars in PG&E procurement costs:

June 1, 2017: PG&E files its 2018 ERRA Forecast Application (A.17-06-005).

July 7, 2017: A diverse group of customer representatives and ratepayer advocates including CCAs, Irrigation Districts, AReM/DACC, and ORA file responses to this Application. Many of these highlight PG&E's failure to demonstrate prudent management of contracts.[16]

July 17, 2017: PG&E replies to protests arguing that PG&E's administration of procurement contracts, as well as its management of procurement portfolios are outside the scope of an ERRA forecast proceeding and best addressed in the compliance phase, and "[t]he Joint CCA Parties can conduct a review of how PG&E administered its procurement contracts, including whether there were actions it could have or should have taken to reduce procurement costs, in the ERRA Compliance proceeding."[17]

July 12, 2017: Pre-hearing conference - Joint CCAs argue demonstration of prudent contract management should be in scope of ERRA Forecast.

Aug 4, 2017: Scoping Memo and Ruling of Assigned Commissioner is issued, agreeing with PG&E's position that "PG&E's administration of procurement contracts, as well as its management of procurement portfolios are outside the scope of an ERRA forecast proceeding and **best addressed in the compliance phase**."[18]

Feb 28, 2018: PG&E files ERRA Compliance Application (A.18-02-015) seeking recovery of costs for 2017.

[16] *See* Protest of the City and County of San Francisco (A.17-06-005), at 2 ("the record indicates that PG&E is not prudently managing its portfolio"); Protest of Marin Clean Energy, Peninsula Clean Energy Authority, the Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority to PG&E's Energy Resource Recovery Account Application (A.17-06-005), at 3-6 ("while PG&E professes concern for its bundled customers' costs in making the unsubstantiated claim that the current PCIA results in a cost-shift to bundled customers, it ignores the fact that the lack of prudent contract management may be a driving factor in increasing those costs.").
[17] PG&E Reply to Protests for Application (A.17-06-005) at 3-5.
[18] Scoping Memo and Ruling of Assigned Commissioner (A.17-06-005) at 3 (emphasis added).

Apr 6, 2018: SCP and ORA submit protests because PG&E's portfolio management practices were not prudent and did not minimize ratepayer costs.[19]

Apr 16, 2018: PG&E replies that "Prudence Review Of PG&E's Portfolio Management Is Inconsistent With Pubic Utilities Code Section 454.5(d)(2)" and should therefore not be in scope for the ERRA Compliance proceeding. PG&E later clarifies that "the question of whether PG&E prudently administered and managed its QF and non-QF contracts in accordance with the contracts' provisions is within the scope of the proceeding. But that issue does not encompass either of the issues raised by SCP, portfolio management and load forecasting."[20]

Apr 27 2018: Pre-hearing conference. SCP requests that prudent management be recognized within scope in ERRA Compliance Proceeding. PG&E argues their bundled procurement plan is the appropriate venue for determining these issues as the ERRA Compliance proceeding determines whether the utility complied with the plan. SCP notes that bundled procurement plans are silent about contract management.

May 14, 2018: Scoping Memo and Ruling of Assigned Commissioner is issued, finding that "this proceeding will not evaluate longer term decisions such as whether or not to continue to operate a plant; that is **more appropriate for a general rate case or a separate application proceeding**."[21]

This timeline describes how parties first sought review of IOU portfolio management in the ERRA forecast docket, but were told to await the ERRA compliance docket. When the same parties then sought review of IOU portfolio management in the ERRA compliance docket, the Commission again deferred its statutory duty and told parties that such a review was more appropriate for a general rate case or a separate application proceeding. The parties are still waiting for the Commission to meet its statutory responsibilities, while all customers continue to suffer the consequences of avoidable costs being included in setting their rates.

[19] *See* Protest of Sonoma Clean Power (A.18-02-015) at 2-3 ("SCP protests this Application on two grounds, 1) that PG&E's portfolio management practices were not prudent and did not minimize ratepayer costs, and, 2) that PG&E's bidding behavior distorted market prices to the detriment of CCA customers."); *see also* Protest of ORA (A.18-02-015) at 3 (Based on its initial review, ORA identified the following issue to be within the scope of the proceeding: "[w]hether PG&E administered and managed its own generation facilities prudently, according to Standard of Conduct 4 (SOC 4).").
[20] Reply of PG&E (A.18-02-015) at 5 & 7.
[21] Scoping Memo and Ruling of Assigned Commissioner (A.18-02-015) at 5 (emphasis added).

Thus, not only has the Commission failed to meet its statutory responsibility in this proceeding under Sections 380, 454.5, and 399.11-399.20 and ensure that only unavoidable costs are included in the PCIA under Section 366.2(f)(2), the Commission continues to fail, as described in the timeline above, to conduct the statutorily-required prudency review of IOU portfolio management that will ensure that all customers – bundled and unbundled— are paying rates based on only unavoidable costs.

While the PCIA Decision sets forth that Phase 2 will consider *future* portfolio optimization and shareholder responsibility for future portfolio mismanagement, the Commission abuses its discretion and ignores its statutory responsibilities by ignoring record evidence of *past* portfolio mismanagement in setting a new PCIA that includes costs associated with that past mismanagement. PCE, MCE, and SCP all agree that it is important to reform utility portfolio management practices to ensure future costs are as low as possible, however, the Commission must also ensure costs being included in 2019 rates meet all statutory requirements. The Commission should grant rehearing to ensure that all ratepayers are made whole for the past mismanagement of the utilities regarding the utilities' unnecessary accumulation and pass through of above-market costs.

B. The Record Provides A Basis For Finding That the IOUs Failed to Prudently Manage Their Generation Portfolios to the Detriment of All Ratepayers

The Commission not only fails to meet its statutory duty to set the new PCIA based on a factual and legal determination that the IOUs incurred legitimately unavoidable costs and took all reasonable steps to minimize above-market costs, the record provides a basis to conclude that the IOUs were responsible for imprudent management of their generation portfolios that created significant above-market costs to the detriment of all ratepayers. The Commission should not ignore this record evidence. Instead, the Commission must acknowledge and take steps to remedy this past conduct and establish a PCIA rate that specifically accounts for the established utility mismanagement. At the very least, enough evidence exists so the Commission should explore these concerns of past mismanagement more thoroughly in Phase 2. The PCIA Decision fails to acknowledge or even discuss the proven deficiencies of the IOUs to forecast and account for CCA departing load.

1. By Failing to Conduct Proper Forecasting and Make the Proper Adjustments to Its Procurement Strategies, the IOUs Harmed All Ratepayers By Passing Through Avoidable Above-Market Costs

At hearings, SCE and PG&E confirmed that the IOUs disregarded the Commission's longstanding guidance in Decision 04-12-046 and Decision 04-12-048 by establishing a narrowly defined threshold for forecasting departing load. For example, SCE Witness Cushnie explained that:

> [i]n the case of Southern California Edison, what we're looking for is for the newly-forming CCA to give us sufficient confidence as to their formation plans so that we can then plan to balance the portfolio around their formation intentions. To date, only one of our CCAs has provided a binding notice of intent….[22]

PG&E Witness Lawlor similarly explained that based on MCE's implementation plan, "it looks like [the CCA is] negotiating a long-term electricity supply contract"[23] and that PG&E does not "manage to a departure. We had an open need, and we manage it in a bundled way."[24] Witness Lawlor explained that "[a]t the time we did not use the forecast for forecasting load departure. We concluded we needed to use more of a bright line methodology, and that looked at binding notice of intent or basically when they go live."[25]

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[22] *See* 4 Tr. 809: 20-810:26 (Cushnie).
[23] 4 Tr. 813: 9-10 (Lawlor) and 4 Tr. 817: 13-820:16 (Lawlor).
[24] 4 Tr. 822: 18-28 (Lawlor).
[25] 5 Tr. 857: 12-21 (Lawlor).

The record evidence in this proceeding clarifies that by the IOUs' admitted failure to conduct proper forecasting and adjust their procurement strategies appropriately, the IOUs harmed all ratepayers by passing through above-market costs.

2. PG&E Willfully Ignored MCE's Departing Load in 2010 and Failed to Adjust Its Portfolio – Again Harming All Ratepayers

PG&E's actions in the face of MCE's departing load in 2010 provides a more specific example in the record of this proceeding of IOU portfolio mismanagement that harmed all ratepayers. PG&E admitted it formally knew of MCE's load departure well before that departure through MCE's CPUC-certified implementation plan, but ignored such notice[26] (the implementation plan indicated departing load in 2010, forecasts of load growth through 2019, and indications of active negotiations for long-term power contracts to serve this load).[27] Yet PG&E continued to execute long-term contracts in 2010 (representing approximately 1.7 GW of capacity) that did not account for MCE's actual and reasonably forecastable departing load – which were executed *after* MCE submitted its implementation plan and some of which were executed after certification of MCE's implementation plan by the Commission, and approximately 600 MW of which was executed after MCE launched.[28] As a result, <u>all</u> customers are paying for these avoidable costs.[29]

By failing to acknowledge the record evidence of past utility mismanagement, the PCIA Decision unlawfully sets a new PCIA on an established record of inappropriate above-market costs that have harmed all ratepayers. The Commission should take this opportunity afforded by

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[26] 4 Tr. 822: 3 (Lawlor); 5 Tr. 857: 12-21 (Lawlor).
[27] 4 Tr. 817: 13-822: 3 (Lawlor); 5 Tr. 857:13-21 (Lawlor); *see also* CalCCA Brief at 99.
[28] *See* Exh. CalCCA-123, Maximum Contract Capacity; *see also* Exh. CalCCA-123, PG&E 2010 Contract Execution Dates from Attachment 10 ALJ Requested Data Matrix.
[29] Even more egregiously, MCE customers who departed from PG&E in 2010 are still today paying for these costs that should not be attributed to them.

its close examination of utility above-market costs to hold the utilities accountable for their past mismanagement. A new PCIA rate should specifically account for the Commission's resolution of that past IOU mismanagement that created avoidable costs.

II. THE PCIA DECISION FAILS TO MEET THE REQUIREMENTS OF SECTIONS 365.2 AND 366.2(F)(2) BY UNLAWFULLY ATTRIBUTING COSTS TO THE EARLIEST DEPARTING LOAD CCA CUSTOMERS (INCLUDING THOSE SERVED BY PCE, MCE, AND SCP) THAT PG&E ADMITS WERE NOT INCURRED ON BEHALF OF THAT DEPARTING LOAD

The PCIA Decision ignores record evidence that the PCIA has included costs for early departing load customers, including those served by PCE, MCE, and SCP, that PG&E admits were not incurred on behalf of that departing load. Thus, the PCIA Decision and new PCIA methodology is not based on substantial evidence and fails to meet the requirements of Sections 365.2 and 366.2(f)(2).

Sections 365.2 and 366.2(f)(2) limit cost recovery from CCA customers to those costs attributable to those customers. The Commission has long endorsed the approach that procurement costs cannot reasonably be attributable to customers unless a utility procures a resource to serve those customers after accounting for reasonable anticipated departing load.[30] To mitigate the risk of unnecessary resource commitments that may become stranded due to departing load, longstanding Commission policy has directed the utilities to forecast departing load using all available information.[31]

Yet, PG&E admitted it ignored these directives. Instead, PG&E adopted a self-serving and narrow threshold for forecasting departing load that required almost near-certainty that load would depart.[32] PG&E ignored various indications of load departure (actual and imminent) to

[30] *See* D.03-04-030 at 54; D.04-12-046 at 30; D.04-12-048, Ordering Paragraph 9 at 239.
[31] *See* D.03-04-030 at 54; D.04-12-046 at 30; D.04-12-048, Ordering Paragraph 9 at 239.
[32] *See* 4 Tr. 809: 20-810: 3 (Cushnie); 4 Tr. 813: 9-15 (Lawlor); 4 Tr. 817: 13-820:16 (Lawlor); 4 Tr. 814: 8-16 (Lawlor); 4 Tr. 821: 26-822:3 (Lawlor); 5 Tr. 857: 13-21 (Lawlor); *see also* CalCCA Brief at 98-99.

justify its procurement on behalf of departing load for as long as possible.[33] Particularly in the early years of CCA formation, PG&E's unreasonable threshold for forecasting load departure resulted in PG&E ignoring the potential for dramatic future increases in CCA customer departure as PG&E actively and aggressively executed long-term power contracts. Only in complying with Decision 14-02-040, after substantial load departure, did PG&E forecast CCA departing load in its bundled procurement plan.

PG&E admitted that clear knowledge of imminent and actual departing load did not cause it to alter its procurement practices and portfolio management. In the context of MCE's initial departure in 2010, PG&E opined that such a small amount of departing load (.1% to .2% of PG&E bundled load) was not significant enough to alter PG&E's procurement in any way.[34] In fact, PG&E admitted that it would take load departures <u>of greater than 10-20%</u> before it made <u>any</u> portfolio adjustments.[35] Moreover, in defending its decision to continue to buy on behalf of MCE customers in 2010 despite MCE's actual launch, PG&E indicated that its 2010 executed contracts were "purchased . . . knowing that [PG&E] needed to meet its RPS targets on a total portfolio basis . . . ."[36] Contrary to the requirements of statute and Commission decisions, PG&E admitted, "We don't manage to a departure. We had an open need, and we manage it in a bundled way . . . We would have continued to procure based on the *bundled* total need."[37]

PG&E's admission that no amount of CCA departures up to 10-20% would be cause to change PG&E's procurement practices makes clear that procurement up to 10-20% of PG&E's load should <u>not</u> be attributable to departing CCA load. By its own admission, PG&E held all of

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[33] *See* 4 Tr. 809: 20-810: 3 (Cushnie); 4 Tr. 813: 9-12 (Lawlor); 4 Tr. 814:7-11 (Lawlor); 4 Tr. 817: 13-822: 3 (Lawlor); 5 Tr. 857: 13-21 (Lawlor).
[34] 4 Tr. 814:7 – 11 (Lawlor); 4 Tr. 822: 24-823: 20 (Lawlor); 5 Tr. 853:25-854:2 (Lawlor).
[35] 1 Tr. 37:17-21 (Wan).
[36] 4 Tr. 822: 24-823: 20 (Lawlor).
[37] 4 Tr. 822: 24-823: 20 (Lawlor) (emphasis added).

its resources acquired prior to 10-20% CCA departure to benefit bundled customers, while allocating costs to departing load customers. Either PG&E continued to hold all of its resources acquired prior to 10-20% CCA departure to benefit bundled customers or PG&E failed to act in accordance with state law and Commission policy to forecast departing load and manage its portfolio. Both scenarios violate indifference, and the Commission's failure to address and act upon this evidence violates Sections 365.2 and 366.2(f)(2)-(g).

By failing to even address this evidence, much less ensure CCA customers only pay for costs attributable to them, the PCIA Decision perpetuates the harm caused to early departing load customers—including those served by PCE, MCE, and SCP. The Commission's inaction sanctions the attribution of costs that PG&E admits were not incurred on behalf of our departing load. Thus, the PCIA Decision fails to meet the requirements of Sections 365.2 and 366.2(f)(2)-(g) and the new PCIA methodology is not based on substantial evidence. Furthermore, the PCIA Decision compounds those failures by foreclosing the opportunity in Phase 2 of this proceeding to gather further evidence that would assist in identifying with further specificity which costs incurred by the IOUs are appropriately attributable to CCA customers and determine how best to correct for any costs improperly attributed to other CCA customers in prior years.

III. CONCLUSION

The Commission should not hesitate to use the opportunity afforded it by the PCIA proceeding to hold the IOUs accountable for the IOUs' past procurement mismanagement without revisiting the Commission's prior individual procurement decisions. The Commission can do so both by setting the PCIA appropriately prospectively and by taking the opportunity in Phase 2 of the PCIA proceeding to both delve into and correct for the avoidable and unattributable costs that all ratepayers — both bundled and unbundled— may have been burdened with in prior years. For the reasons described above and in CalCCA's application for rehearing, the Commission should grant rehearing.

Respectfully submitted,

November 19, 2018

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 18-06-001 (Filed June 1, 2018)

COMMENTS ON PROPOSED DECISION OF 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

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SUBJECT MATTER INDEX

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COMMENTS ON PROPOSED DECISION OF 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

Pursuant to Rule 14.3, 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 ("CCAs"), submit these comments on Administrative Law Judge Wildgrube's Proposed Decision ("PD") regarding Pacific Gas & Electric Company's ("PG&E's") Energy Resource Recovery Account ("ERRA") application, filed June 1, 2018 ("Application").[1] While the PD correctly rejects PG&E's inappropriate application of unapproved policy changes in this docket, including reaffirming prior Commission precedent that generation must be valued at the Market Price Benchmark, the PD errs in several significant ways that would have an improper and detrimental impact on unbundled customers, including CCA customers. These comments raise, explain and resolve **over $400 million worth of legal and factual errors** currently within the PD.

This year's ERRA forecast Application requires the Commission to address two major, novel issues. The first is the implementation of Decision ("D.") 18-10-019 in the Power Charge Indifference Adjustment ("PCIA") docket ("D.18-10-019" or the "PCIA Decision"), R.17-06-026. The implementation of D.18-10-019 includes establishing the new benchmarks for Resource Adequacy ("RA") capacity, Renewable Portfolio Standard ("RPS")-eligible energy, and brown power in that decision. It also includes implementing the limited rate design changes enacted therein, *i.e.*, the decision to move away from the "Top 100 Hours" allocation methodology. Finally, the PCIA Decision establishes a brown power true-up in order to increase the accuracy of the PCIA, an effort the Commission has emphasized should take place in the near term.

Taking the true-up first, the PD errs by delaying its implementation, essentially resolving ambiguity within the PCIA Decision in a manner that ignores the strong policy underpinnings of that docket to establish a more accurate and transparent PCIA rate as soon as possible. There is no practical reason to delay implementation—PG&E will have the data it needs to true up 2018's forecasted brown power rates with 2018's year-end actuals in time to implement this decision within a reasonable

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[1] A.18-06-001, *Application of Pacific Gas and Electric Company (U 39 E) for 2019 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation* (June 1, 2018) ("Application").

timeframe. Failing to address this issue in the PD unjustifiably ignores a **$267 million overpayment error**, $109 million of which is from unbundled customers without a mechanism to make them whole.

Beyond the brown-power true-up, the PD's other conclusions on implementing D.18-10-019 are sound: (1) PG&E has correctly updated those benchmarks based on the PCIA Decision, and (2) ratemaking changes should be limited to those approved by D.18-10-019, meaning a PG&E proposal in this docket to move away from system-level billing determinants when calculating the PCIA ($/kWh) for each class within each vintage, *i.e.*, the utility's "billing determinants" proposal, should be rejected. While the PD gets these two conclusions right, it contains a calculation error when determining the impact related to the latter finding. Rejecting PG&E's "billing determinants" proposal should reduce the PCIA revenue requirement by **$88.0 million** – an amount much greater than the $22 million reduction currently shown in the PD.

The second major issue is that the Application shows PG&E is a major seller of RA capacity, RPS-eligible energy and brown power for the first time this year. For example, PG&E sold 2,050 MW of RA capacity just in the five months between its June Prepared Testimony and its November 7, 2018 updated testimony ("November Update").[2] With only a glancing acknowledgment of the proposal in its Prepared Testimony, and zero explanation, justification or reasoning provided for it therein, PG&E proposed novel treatment for forecasting these sales. This policy change does not comply with prior Commission precedent and would inappropriately set precedent for other utilities in the State in a single utility's ERRA proceeding. The PD rightly rejects it and concludes multi-year sales of energy and capacity should be valued at the relevant benchmarks.

However, here again, the PD's calculations appear to be off. Rejection of PG&E's policy proposal to value multi-year sales at values other than the benchmark should reduce the PCIA revenue requirement by **$34.2 million**. Adding this to the $88.0 million from rejecting PG&E's billing determinants proposal, the PD as it is currently written should reduce the overall PCIA revenue requirement by **$122.2 million** from the level requested in the November Update, resulting in a PCIA revenue requirement of **$1.042 billion**, a much greater decrease than the PD currently reflects.[3]

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2 Exh. Joint CCAs-11.

3 Proposed Decision at 2, Conclusion of Law 1, Ordering Paragraph 1. The Proposed Decision adopts a PCIA revenue requirement of $1.142 billion, which is $22 million lower than the $1.164 billion amount PG&E requested in its November Update. Exh. PG&E-6, 1:19-20.

Finally, the PD falls short on other issues that arose from the November Update and related discovery from the Joint CCAs. Namely:

- PG&E should be required to develop a mechanism to include tax savings in unbundled customers' 2019 PCIA rates since bundled customers will receive such a benefit in their 2019 generation rates according to PG&E's Annual Energy True-up advice letter ("AET"). Failure to do so results in unjustified, disparate treatment of customer groups.

- Easily resolved transparency issues should be addressed in the PD either by establishing a forum in which all stakeholders can participate or via PG&E-specific provisions.

- The PD should clarify that all affected customers, including unbundled customers, will benefit simultaneously from a refund related to PG&E's accounting errors found in an audit in April 2018.

- The PD should be revised to appropriately reflect its conclusions regarding direct access customers' responsibility to pay for legacy utility-owned generation ("UOG").

Accordingly, the final PCIA revenue requirement within the PD should be corrected to the amounts discussed herein. Moreover, to ensure the Commission's directives are appropriately enacted in accordance with General Order 96-B, the PD's ordering paragraphs should also require PG&E to (1) conform its calculations to the final decision's findings and conclusions and (2) calculate and publish the results of both (a) the final PCIA revenue requirement and (b) the final Table 14-3 (listing the PCIA for each class within each vintage) in a **Tier 2 Advice Letter** rather than a Tier 1 Advice Letter. Appendix A to this filing reflects the changes to the Findings of Fact, Conclusions of Law and Ordering Paragraphs necessary to enact these corrections. Appendix B includes a revised version of PG&E's Table 14-3 corresponding to the revised PCIA revenue requirements discussed herein, that result from (1) correctly calculating the PCIA under the PD as it is currently written, (2) correctly calculating the PCIA under the PD as it is currently written and including a 2018 brown power true-up, and (3) correctly calculating the PCIA if all of the Joint CCAs' recommendations in these Opening Comments are adopted.

I. Ambiguity Regarding the Brown Power True-Up Should be Resolved in Favor of Establishing More Accurate and Transparent Rates As Soon As Possible.

The difference between the forecasted brown power component of the 2018 PCIA revenue requirement and the revenue requirement based on actual 2018 market transactions to date is **$267**

million for the 2018 vintage.[4] This means unbundled customers have paid **$109 million more** than they should have in 2018 (a 40.7% share of the indifference amount for that vintage), which is an illegal cost shift the law does not permit.[5] No mechanism exists to make unbundled customers whole for this overpayment except for the brown power true-up adopted in D.18-10-019—and then only if 2018 is the target year for that true-up.

The brown power true-up "is, methodologically, a significant advance compared to our current practices."[6] Its purpose is to "increase the accuracy of the PCIA cost allocation between bundled and departing load customers,"[7] and "ensure that bundled and departing load customers pay equitably (*i.e.*, *pro rata*) for non-RA, non-RPS PCIA-eligible resources."[8] For this reason, the PCIA Decision 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."[9] Unlike its treatment of the RA and RPS true-ups,[10] and the Portfolio Allocation Balancing Account ("PABA") and ratemaking changes,[11] which have specific implementation dates or deadlines, D.18-10-019 does not include any discussion of implementing the brown power true-up within a specific timeframe. This omission creates an ambiguity in the PCIA Decision regarding when the true-up should be implemented.

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4 This can be seen by revising PG&E's November 2018 Update Chapter 9 workpapers in A.17-06-005, file "09.ERRA_2018-Forecast_WP_PGE_20171102_Ch09-Standard WP as filed-CONF_WP-B.xlsx." On the "Input" tab in cell D13, the value for "Base Load Weighted Average Price ($/MWh)" can be replaced with the actual brown power average price from the CAISO markets of $39.64 per MWh. The amount of $267 million can be calculated by subtracting the new values shown on Line 45 "Adjusted Indifference Amounts w/ ff&u" of the "Indifference Amount Calc" tab after updating the brown power price compared to the values shown in PG&E's original workpaper file.

5 Cal. Pub. Util. Code § 365.2 (stating "The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."); Cal Pub Util Code § 366.2(f)(2) (stating "A retail end-use customer purchasing electricity from a [CCA] pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following … any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer's purchases of electricity from the[CCA] through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.").

6 D.18-10-019 at 142.

7 *Id.* at Finding of Fact 15.

8 *Id.* at Conclusion of Law 16.

9 *Id.* at Ordering Paragraph 6.

10 *Id.* at 142.

11 *Id.* at 124, Ordering Paragraph 7.

The PD inappropriately resolves that ambiguity by delaying the true-up, stating "[t]he data to be used for a true-up will be for January 1, 2019 through December 31, 2019." [12] Under the PD's approach, unbundled customers would not realize any true up from 2018 overpayments, and the effect of D.18-10-019 on customers' bills would not be felt *until 2021 rates*. This is because the data required to implement the true-up would not be available until after December 31, 2019, pushing implementation to either the 2020 ERRA compliance, or the 2021 ERRA forecast, both of which impact 2021 rates.

The PD's delay contrasts with the PCIA Decision's repeated emphasis on the importance of achieving accuracy in setting the PCIA rate and Commissioners' statements that this be achieved as soon as possible. The purpose of the PCIA Decision is, in part, "to determine with unprecedented precision the nature of the costs incurred by the Joint Utilities," and to "adopt an annual true-up requirement to ensure that any forecast-related errors in the annual PCIA are reconciled and cost-shifting is prevented."[13] Deferring a true-up to a later date will fail to "ensure that bundled and departing load customers pay equally for PCIA-eligible resources."[14] Delay also contravenes Commissioner Guzman-Aceves's statements at the October 11, 2018 Commission meeting:

> *The most important thing* from this decision I believe is the issue of transparency, and the ability to finally true-up these costs with actuals … [W]e should deal with actuals, and I think this is the greatest part of this decision is that we're actually going to be tracking what the costs were, and digging those out appropriately.[15]

Commissioner Rechtchaffen's concurrence also emphasizes expedience stating: "I am encouraged that the decision adds a true-up to reflect real market costs for the brown power value of the resources included in the PCIA, and that our goal is to develop a true up process for [RA] and [RPS] values by the end of 2019. In my view *the sooner that this can be done, the better.*" [16]

There is no reason to delay or wait until 2019. Commission ordering paragraphs without timelines associated with them should be implemented immediately unless a stay is granted or it is impossible to comply with the order, neither of which are the case here. As PG&E explains:

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12 Proposed Decision at 17, Conclusion of Law 5 ("A true-up of brown power beginning in 2019 based on 2019 market transactions would comply with Decision 18-10-019.").

13 D.18-10-019 at 62, 129. *See also id.* at 25 (explaining TURN's suggested true-up is to "ensure total PCIA collections are ultimately based on the actual net costs of the IOUs' relevant resources").

14 *Id.* at 72.

15 Commissioner Guzman-Aceves's Comments on D.18-10-019, October 11, 2018 Commission Business Meeting (available at: https://www.youtube.com/watch?v=JIvfwiC6Oo4) (emphasis added).

16 D.18-10-019, attached *Concurrence of Commissioner Rechtschaffen.*

> The "Brown Power [MPB] true-up" will involve recording actual revenues received in the California Independent System Operator (CAISO) market for the PCIA-eligible generation resources that are bid into the CAISO market. As such, the "Brown Power [MPB] true-up," has no "transaction term". The true-up of the Brown Power MPB will involve recording actual net revenues received in the CAISO market for the PCIA-eligible generation resources that are bid into that market. That is, <u>*each PCIA-eligible generation resource bid into the CAISO market will receive revenues and charges for energy and ancillary services and the net revenues for each PCIA-eligible resource will be recorded to the applicable PABA subaccount, which effectively is the true-up for the Brown Power MPB*</u>.[17]

The information necessary to true up all of 2018 will be available within 55 business days of December 31, 2018 since it takes that amount of time for CAISO to provide final settlement data.[18] That is, a brown power true-up can be implemented within three months after the end of the "subject year," or less than three months if preliminary settlement data (available from CAISO after 12 business days) is used.[19] Thus, there is no practical reason 2018 should not be the "subject year" for the first true-up.

As such, the true-up should be implemented via this decision, and unbundled customers' 2019 rates should include the net refunds from overpaying during 2018. On January 10, 2019, PG&E will have the final settlement data it needs for the true-up for most of the 2018 calendar year. The November and December figures can be determined utilizing the preliminary settlement data to which PG&E will have access soon after January 10, 2019. PG&E can use that data to implement the true-up, and demonstrate the impacts on the PCIA, via the Tier 2 advice letter the Joint CCAs believe should enact this decision. The final ratemaking changes would be made via the AET. This change will properly ensure that any ambiguity within D.18-10-019 will be resolved in compliance with the law and in a manner that responds to the PCIA Decision's quest for accuracy as soon as possible.[20]

If the Commission declines to adopt this approach, it should at least require the true-up to be implemented as part of the 2020 ERRA *Forecast* proceeding. By the time of its June 1, 2019, filing,

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17 Joint CCAs Exhs. 19 and 22 (emphasis added); *see* also D.18-10-019 at Ordering Paragraph 7.

18 California System Operator, *Settlement and Billing Business Practice Manual*, § 2.3.2 (July 24, 2018).

19 *Id.*

20 The anticipation of a Dec. 13, 2018, decision in this case originally required the Joint CCAs to advocate for implementing the brown power true-up as part of the 2019 ERRA Compliance proceeding. *See* Joint CCAs Comments on November Update at 30-31. The delaying of a decision in this proceeding until the January 10, 2019, Commission business meeting (or later) has provided the necessary window for PG&E to obtain the preliminary settlement data for 2018 actuals and implement the true-up now.

PG&E will have data on the revenues and charges for energy and ancillary services and the net revenues for each PCIA-eligible resource from each PCIA-eligible generation resource bid into the CAISO market. That data will have been recorded to the applicable subaccount, which, per PG&E "effectively is the true-up for the Brown Power MPB."[21]

II. Valuing Multi-Year Sales of Energy and Capacity Reduces the PCIA Revenue Requirement by $34.2 Million, not the $22 Million Figure Represented in the Proposed Decision.

The PD appropriately determines "[t]he sales of [RA] capacity and [RPS] eligible energy should be valued using the Market Price Benchmark" and deviating from this Commission-sanctioned approach would be improper within an ERRA proceeding.[22] Further, "using something other than the market price benchmark to value PG&E's portfolio may not adequately account for benefits remaining with PG&E's bundled customers following sales of these products."[23]

However, the PD errs on this issue in two respects. First, it does not expressly address multi-year brown power sales, which are included in the November Update via "a single, new contract for energy sales from hydroelectric facilities that are not RPS-eligible."[24] These sales should be valued in the same manner as the RA and RPS multi-year sales.

Second, and more critically, rejecting PG&E's policy proposal to value multi-year sales at amounts other than the benchmark should reduce the PCIA revenue requirement by more than the $22 million figure represented in the PD. Valuing sold resources at the benchmarks essentially folds those resources back into both the Total Portfolio Cost (at their original cost) and the Portfolio Market Value (at the benchmarks). In other words, the result is the same as if the sales transaction had not occurred.[25] The result of folding all three types of transactions, RA, RPS and hydro-electric brown power, back into the indifference calculation in this manner is a reduction in the PCIA revenue requirement by $34.2 million, not the $22 million figure in the PD.[26] The PD should be modified to reflect this higher amount

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21 Joint CCAs Exhs. 19 and 22.

22 Proposed Decision at Conclusion of Law 2.

23 *Id.* at 13.

24 Exh. PG&E-6, 4:26-27.

25 Joint CCAs Opening Brief at 18.

26 This can be seen by going to each of the sales sheets in PG&E's complete November Update workpapers and zeroing out the MWh and dollar amounts shown in the rows "MWh Allocation – Incremental," "MWh Allocation – Cumulative," "RA Sales Revenue Allocation – Incremental," and "RA Sales Revenue Allocation - Cumulative" on the sheets "Non-RPS Eligible Hydro Sales" and "RA Sales – November" and the rows "RPS Pool for RSP Sales w/o SVCEA – Cumulative", "RPS Pool for RSP Sales w/o SVCEA – Incremental", "RPS Pool for

and the corresponding PCIA revenue requirement should be lowered accordingly.

III. Declining to Adopt PG&E's Ratemaking Proposals Reduces the PCIA Revenue Requirement by an Additional $88.0 Million.

D.18-10-019 only approved the limited ratemaking change of moving away from the "Top 100 Hours" methodology for allocating each vintage's Indifference Amount to the respective customer classes.[27] This is the first step in the allocation process for the Indifference Amount, assigning a certain percentage of each vintage's Indifference Amount to each customer class.[28] The Joint CCAs do not contest the PD's approval of PG&E's suggested change in its allocation factors.

Buried within its workpapers, however, and left unexplained in its testimony, PG&E proposes a further un-adopted revision in this docket to the second step in the allocation process. Instead of dividing by the forecasted sales, or "billing determinants" (kWh), to be sold to all customers in each class in the system,[29] PG&E's November Update includes an incremental approach that subtracts out the forecasted demand from customers that departed in the prior year's vintage, leaving only the forecasted load of the bundled customers that remained in that vintage.[30] This change, when combined with the modification to the allocation factors described in the previous section, is responsible for 56.5% of the increase in the PCIA between PG&E's September 7, 2018 Rebuttal Testimony and the November Update.[31] The PD appropriately recognizes D.18-10-019 did not approve this change and rejects it,[32] requiring PG&E to "continue to use the system-level billing determinants consistent with its initial testimony."[33]

While the PD squarely addresses the substance of this issue, it does not correctly reflect the impact of its conclusions in the PD's numerical representations. PG&E derives its PCIA revenue

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RSP Sales w/ SVCEA – Cumulative", and "RPS Pool for RSP Sales w/ SVCEA – Incremental" on the sheet "RPS Sales — November." These changes put the valuation of those resources back into the PCIA-eligible portfolio where they are valued at the market-price benchmarks. Please note that PG&E's filed workpapers did not include the three sales worksheets, and the Joint CCAs submitted a data request, receiving the file "ERRA-2019-PGE-Forecast_DR_Joint-EMM_007-Q01Atch01-CONF.XLSX," which does contain them. The Joint CCAs can provide that to the Commission upon request.

27 D.18-10-019 at 122-124.

28 Joint CCAs Comments on November Update at 13-16. These ratemaking issues are explained in detail on pages 11-25 of the Joint CCAs' November 19, 2018 Comments on the November Update.

29 *See* D.18-10-019 at 122 (describing the current allocation methodology).

30 *See* Exh. Joint CCAs-14.

31 *See* Joint CCAs Comments on November Update at 2, n. 6 (describing how this percentage was derived).

32 Proposed Decision at 15-16.

33 *Id.* at 16, Ordering Paragraph 4.

requirement by multiplying the PCIA rate specific to each vintage and customer class by the forecasted departing customer load for the vintage and class.[34] Thus, a change in one set of customers' responsibility for the PCIA is not neutral in terms of the PCIA revenue requirement. Rather, reducing the unbundled customers' responsibility for the PCIA, as the PD appropriately does here, reduces the level of the PCIA revenue requirement on a one-to-one basis. Thus, the correct numerical result of the PD's determinations, therefore, is a net decrease in the PCIA revenue requirement of $88.0 million from the amount PG&E requests in its November Update.[35] The vintage and class-specific PCIA rates that result from both this change and the $34.2 million change discussed above are shown in Appendix B to this filing in the revised "Table 14-3 (Compliant with Proposed Decision)".

IV. The Commission Should Order PG&E to Adjust the 2019 PCIA on Account of Anticipated Tax Savings.

On March 30, 2018, PG&E filed a Petition for Modification ("PFM") of D.17-05-013 concerning PG&E's 2017 General Rate Case ("GRC").[36] The petition seeks "to pass through the revenue requirement reduction resulting from the lower corporate tax rate set forth in the Tax Cuts and Jobs Act of 2017 (Tax Act)."[37] The tax savings apply to all utility-owned assets, including UOG, but PG&E's Total Portfolio Cost within this docket has not reflected any of this tax savings for the 2018 and 2019 vintages,[38] meaning the Indifference Amount has repeatedly been overstated. PG&E states the tax savings "will be refunded to PCIA customers as part of the 2019 true-up process being developed and implemented as part of the PCIA OIR,"[39] and it plans to propose an approach in its 2020 ERRA forecast application to "incorporate the reduction in costs associated with ongoing tax savings in its 2020 ERRA," provided that the Petition for Modification of D.17-05-013 is granted.[40]

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[34] See file "ERRA-2019-PGE-Forecast_DR_Joint-EMM_007-Q01Atch01-CONF.XLSX." The eligible loads by class and vintage are shown on tab "PCIA BDs by Class by Vintage" in rows 34 to 45. It appears that PG&E failed to include the incremental departed load in the appropriate vintage year, which incorrectly increases the PCIA rate for that vintage. Thus, the values PG&E shows cannot be used to calculate the PCIA rates.

[35] The change in the revenue requirement is correctly derived by using the system load to set rates for all customers instead of the bundled load present in each vintage year. In PG&E's complete November Update workpapers, the load values shown in tab "PCIA BDs by Class by Vintage" in rows 34 to 45 from column D to O should be replaced with the system loads shown in column C. This is the method used in PG&E's prior filings.

[36] Exh. Joint CCAs-23.

[37] *Id.*.

[38] *Id.*.

[39] *Id.*.

[40] *Id.*

The PD's adoption of PG&E's approach unjustifiably discriminates against unbundled customers. Bundled customers will see the benefits of this tax savings via PG&E's AET *in 2019*.[41] Under the PD's adopted approach, unbundled customers will miss out on such tax savings in 2019, while bundled customers will realize such savings. This discrimination is unjustified, and is a result the law prohibits.[42] There is no uncertainty with regard to whether or when the utility will realize the tax savings. The only question is whether PG&E calculated and allocated those savings correctly, a question the Commission is already addressing via the GRC PFM, meaning the cost savings can easily be forecasted with reasonable certainty. Any difference can be addressed in the future true-up for PCIA revenues in the 2019 ERRA Compliance proceeding.

In addition, the nature and timing of the 2019 true-up process is unclear at this point, particularly for utility-owned RPS energy and RA capacity, meaning departed load's ability to realize rate reductions from these tax savings in a timely manner, if at all, is far from certain. D.18-10-019 makes no provision for passing through reductions in UOG costs realized in the year of operation rather in a forecast year. For now, those cost savings can only be captured through the PCIA forecast and, therefore, should be reflected here and now.

The result is a PD that forecasts some reasonably certain costs but not others, to the unjustifiably discriminatory detriment of unbundled customers. Either all customers should realize these tax savings in their 2019 rates or no customers should. The PD should be revised to order PG&E to develop a mechanism to apply to 2019 rates that will adjust the PCIA by reducing the Total Portfolio Cost on account of these anticipated tax savings.[43]

V. The Proposed Decision Declines to Act on Easily Resolved Transparency Problems That Harm Millions of Residential and Non-Residential Customers.

CCA staff answer to elected officials who represent *all* customers in their territory regardless of whether they self-generate or purchase energy from a non-profit provider or a for-profit company. The only advocates at the Commission for the customers that formed CCAs, however, are the CCAs themselves. Recognizing this, the CCAs have repeatedly requested opportunities to revise the annual

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41 Exh. Joint CCAs-7, pp. 5-6, Table 2, line 6 and Note 3.

42 Cal. Pub. Util. Code § 728; *Pacific Tel. & Tel. Co. v. Public Utilities Com.*, 401 P.2d 353, 361 (Cal. 1965) ("the primary purpose of the Public Utilities Act is to insure the public adequate service at reasonable rates without discrimination").

43 Alternatively, PG&E should not be permitted to pass on these tax savings to its bundled customers until unbundled customers in its territory benefit from these changes as well.

ERRA process to ensure both stakeholders and the Commission have sufficient time to adequately analyze the convoluted but high-stake issues in an ERRA proceeding, while also acknowledging the need to litigate the proceeding on an expedited timeline. It is incumbent upon CCAs to assist the millions of unbundled customers in California in planning for rate changes in the ERRA that, in the past, have led to significant, volatile and near-term changes in customers' monthly electricity bills. The opacity of PG&E's filings, and the Commission's ERRA framework in general, repeatedly and consistently frustrate CCAs' efforts to advocate for their customers, and the PD's unwillingness to act on this issue furthers such harm.

In this docket alone PG&E has proposed substantial shifts in policy both unrelated to the PCIA Decision and in the name of implementing it. The utility did not explain at all in its prepared testimony its decision to value multi-year sales contracts at a level other than the applicable benchmark. Likewise, its November Update included almost no explanation—and certainly no justification—for its change to the "billing determinants" issue when calculating the $/kWh PCIA rate. In both cases, investigating the answers took substantial time and the effort to sift through dense, incomplete and inscrutable workpapers and submission of repeated rounds of discovery. In the case of the billing determinants issue proposed in the November Update, the CCAs were required to conduct such investigation, including a workshop, a meet-and-confer, three sets of data requests, a motion to admit new evidence and the preparation of 37-page comments within 12 calendar days.

Further complicating CCAs' ability to meaningfully plan on behalf of their customers, PG&E's November Update does not contain the rates that will go into effect in 2019, just weeks from when the update was filed. That is, the actual rates—the $/kWh figure—the Joint CCAs' customers will pay *are still hidden and will remain hidden until the very last moment* before implementation when the final AET is filed.[44]

Whether intentional or not, the opacity of PG&E's Application, coupled with the shortened timeframe of the proceeding, and varying levels of participation from other entities representing ratepayer interests from year to year, favors PG&E because the utility "holds all the cards." Without clear upfront explanations regarding revenue requirements or proposed changes to policy, parties are left to slog through dense Excel spreadsheets, painstakingly connecting one cell to another to determine

[44] Adding further complexity and confusion, PG&E publishes a bundled "generation" rate that in fact excludes a significant portion of the Utility Generation Balancing Account, or UGBA, so it is not readily possible to compare CCA rates to proposed PG&E rates.

what exactly the utility is proposing and how it will impact customers. Even then, confirmation of those analyses can only be obtained from a discovery process that is frequently less than helpful in providing clear answers and explanations. The lack of clarity leaves market participants representing millions of customers unable to rationally plan for and reasonably anticipate near-term rate impacts—a far cry from the transparency principles the Commission has supported in the PCIA docket and elsewhere.

Rather than address this issue, the PD "decline[s] the invitation to alter the structure of ERRA forecast proceedings generally."[45] That was not the Joint CCAs' request in this docket. Via an Opening Brief, Reply Brief and Comments on the November Update, the Joint CCAs requested Commission guidance for a forum in which more concrete procedural mechanisms, such as the following, might be adopted for all IOU ERRA processes:[46]

- Planned workshops soon after the application is filed in which the utility would explain any significant changes in methodology or policy underlying the application,
- Use of the modified non-disclosure agreement from the PCIA proceeding to allow counsel and CCA personnel access to confidential workpapers to increase collective understanding and transparency,
- Expedited discovery timelines,
- A longer procedural schedule,
- A required update to the AET concurrent and consolidated with the November Update (or elimination of the AET altogether) so that CCAs know the rates their customers will soon pay, and/or
- Scheduling of prehearing conferences closer to the application date.

These are reasonable—and easily enacted—requests when compared with the substantial impact the ERRA proceedings have on millions of Californians. The Joint CCAs' simple request for a forum in which to have this conversation should be granted and the PD revised accordingly. Even if the Commission is unwilling to initiate a broader discussion on these issues, it should at least revise the PD to require changes to the PG&E-specific ERRA forecasting framework going forward.

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45 Proposed Decision at 14.

46 Joint CCAs Opening Brief at 21-24; Joint CCAs Reply Brief at 3; Joint CCAs Comments on the November Update at 31-34.

VI. Clarification Should be Provided if the PD's Recommendations are Adopted Regarding Overcollections from a PG&E Accounting Error.

In the November Update, PG&E describes a $141.3 million error it committed in allocating costs from June 2012 to May 2018 related to CAM-eligible contracts, including the Marsh Landing Generating Station ("Marsh Landing"), and revenues from ancillary services from CAM-eligible resources.[47] "The errors resulted in an over-collection of revenue from customers paying the costs in ERRA, and corresponding under-collections from customers paying the costs in" the New System Generating Balancing Account ("NSGBA").[48] That is, instead of allocating costs and revenues associated with Marsh Landing and other CAM contracts via the CAM, they were allocated via the ERRA balancing account instead, resulting in the overcollection.

PG&E discovered the error in an *April* 2018 audit and recorded associated changes to pull the costs out of the ERRA balancing account in *June* 2018.[49] Despite knowing the errors existed, PG&E neither updated its testimony in this proceeding, where the NSGBA is determined, nor included the updated accounting in Exh. PG&E-2, the utility's rebuttal testimony filed on September 7, 2018, a filing that did include new information about its RA and RPS sales and a revised Total Portfolio Cost. Instead of crediting customers for the overcollection in this docket, ensuring customers, including CCA customers that were bundled customers at the time of the overcollection, receive these refunds in 2019 rates, PG&E proposes in the November Update to wait to address the issue in the 2019 ERRA compliance and 2020 ERRA forecast proceedings.[50]

The PD concludes "[i]t is reasonable to address misallocated CAM related costs in the 2019 ERRA compliance and 2020 ERRA forecast proceedings."[51] The Joint CCAs continue to believe this approach should be rejected, and PG&E should reallocate the costs to all affected customers as a one-time adjustment as part of this proceeding for the reasons stated in the Joint CCAs' Comments on the November Update.[52] However, if the PD's approach is adopted, the decision in this case should include

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[47] Exh. PG&E-6, 8:1-11:2. Pursuant to the utility's preliminary statement for the NSGBA, the CAM should be the mechanism to recover "the capacity and energy costs for the Marsh Landing PPA." PG&E, Electric Preliminary Statement, Part FS, New System Generation Balancing Account (Effective January 1, 2017).

[48] Exh. PG&E-6, 9:1-3. It also included a forecasted overcollection of $196,053,058 for the ERRA balancing account in its AET Advice Letter 5376-E that includes the error. *See* Exh. Joint CCAs-16.

[49] Exh. PG&E-6, 9:7 to 10:11; Exh. Joint CCAs-16.

[50] Exh. PG&E-6, 10:18 to 11:2.

[51] Proposed Decision at Conclusion of Law 3.

[52] Joint CCAs' Comments on the November Update at 25-26.

a finding that CCA customers that were bundled customers at the time the costs were misallocated will be entitled to a refund commensurate with that provided to unbundled customers.[53]

VII. The PD Should be Revised to Correctly Reflect the CCAs' Burden of Proof and the PD's Conclusions Regarding Direct Access Customers' Responsibility to Pay for Legacy UOG.

The Joint CCAs' Comments on the November Update described how the same amount of energy forecasted to serve direct access customers was excluded from the "Legacy UOG" vintage in the updated Table 9-4 that is part of PG&E's November Update.[54] This omission was either an error or an implication by PG&E that direct access customers are no longer responsible for legacy UOG costs, nor UOG costs from 2002-2009. The PD's conclusion regarding the incremental billing determinants issue, discussed in detail *supra*, addresses the issue underlying this problem with the "Legacy UOG" vintage. By requiring PG&E to "continue to use the system-level billing determinants consistent with its initial testimony,"[55] the PD has addressed the shortcomings the Joint CCAs demonstrated exist within PG&E's testimony and workpapers. The PD should be revised to reflect this fact.

The Commission should also revise the PD's determination that "[t]he 'implication' the Joint CCAs draw from this appearance is insufficient to meet the Joint CCAs burden to call into question the reasonableness of PG&E's treatment."[56] PG&E, as the applicant, has the burden of affirmatively establishing the reasonableness of all aspects of its application,[57] and that burden of proof generally is measured based upon a preponderance of the evidence.[58] Here, the only evidence shows PG&E's exhibit contains either an error or an unjustified omission – it is missing 6,440 GWh of load in its "Legacy UOG" vintage compared to its overall system load. The PCIA Decision clearly allocates responsibility for these costs to *all* customers, and the Joint CCAs meet their burden by raising this issue and explaining it in detail via the only procedural vehicle available to them to do so—comments on the

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[53] Further, the shift in costs from generation to distribution rates should occur simultaneously for unbundled and bundled customers so as to avoid having unbundled customers paying twice (now via the CAM revenue requirement) for resources for which they have already paid (via the ERRA revenue requirement).

[54] *Id.* at 27-28.

[55] Proposed Decision at 16; Ordering Paragraph 4 (stating "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.").

[56] *Id.* at 16.

[57] D.12-12-030 at 42.

[58] *See, e.g.,* D.18-01-009 at 9-10; D.15-07-044 at 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.").

November Update. The PD should be revised to reflect it is PG&E's burden to establish the reasonableness of each element of its application, and that the utility had failed to do so here.

VIII. PG&E Must Be Ordered to Implement These New Charges Via a Tier 2 Advice Letter.

The PD errs in ordering PG&E to implement the changes it approved and ordered via a Tier 1 Advice Letter. Per General Order 96-B Energy Industry Rules 5.1(3) and 5.2(1), a change to a utility charge is inappropriate where it is the first time a utility is using a particular index or formula. This is the first time PG&E will be implementing the newly-revised PCIA in accordance with the changes approved in D.18-10-019, this Application and the PD.[59] Accordingly, implementation of the Commission's decision in this Application should occur via a Tier 2 Advice Letter. Staff should have an opportunity to review PG&E's first implementation of these changes prior to effectiveness, and all Parties should have an opportunity to review and consider these changes as well (particularly in light of the complexity of this Application and the many calculation errors identified in these comments).

IX. Conclusion

The Joint Parties thank Commission Staff and ALJ Wildgrube for their efforts in resolving the complex issues raised in this docket in an expeditious manner. We respectfully request the Commission revise the PD along the lines enumerated above and in the attached Appendix A's revisions to the PD's Findings of Fact, Conclusions of Law and Ordering Paragraphs.

Dated: November 19, 2018

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[59] Arguably, the changes approved and ordered in the Commission's decision for this Application should be approved via Tier 3 Advice Letter, as they may be more properly viewed as a new "methodology" rather than a new "index or formula."

APPENDIX A

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, Sunrun offers the following index of recommended changes to the *Decision Adopting Pacific Gas And Electric Company's 2019 Energy Resource Recovery Account Forecast And Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation*, including proposed changes to the Findings of Fact, Conclusions of Law and Ordering Paragraphs. The Joint CCAs proposed revisions appear in underline and strike-through.

Findings of Fact

5. A petition for modification of D.17-05-013, PG&E's 2017 General Rate Case is pending to address reduction of the revenue requirement due to the Tax Cuts and Jobs Act of 2017, the benefits of which will be allocated to bundled customers 2019 rates via the AET but not to unbundled customers' 2019 rates.

6. The data for performance of a true-up of brown power for a target year of 2018 will be available in sufficient time to include in 2019 rates ~~will be collected during 2019~~.

7. It is reasonable to value brown power, Resource Adequacy capacity and Renewable Portfolio Standard eligible energy in excess of demand and sold via multi-year contracts using the Market Price Benchmark.

[X]. Revisions to the current ERRA framework will foster the Commission's and customers' ability to understand, plan for and establish just and reasonable rates.

[X]. This decision's conclusion that the calculation of the PCIA rate continue to be determined 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 obviates the issue raised by the Joint CCAs regarding the omission of 6,440 GWh of load in the "Legacy UOG" vintage in the November Update.

Conclusions of Law

1. PG&E's updated 2019 ERRA forecast should be adopted/approved, as follows: 1) adopt a forecast for the 2019 electric procurement revenue requirement of \$2,907.4million for PG&E, which consists of \$1,554.0 million for the ERRA, \$80.3 million for the Ongoing Competition Transition Charge, \$~~1,142.0~~ \$1,042 million for the PCIA, and \$131.1 million for the CAM; 2) approve PG&E's 2019 electric sales and peak load forecasts; 3) adopt a 2019 GHG-related forecast of \$1.083 million for administrative and outreach expenses pertaining to implementation of GHG allowance proceeds return, \$324.5 million net forecast GHG revenue return amount; and adopts a 2019 semi-annual residential California Climate Credit of \$29.18 per customer; 4) find 2017 recorded administrative and outreach expenses of \$1.052 million pertaining to implementation of GHG allowance proceeds return, are reasonable; and, 5) approve PG&E's rate proposals associated with its electric procurement related revenue requirements to be effective in rates January 1, 2019.

2. The multi-year sales of brown power, Resource Adequacy capacity and Renewable Portfolio Standard eligible energy should be valued using the Market Price Benchmark.

3. It is reasonable to address misallocated CAM related costs as part of this 2019 ERRA forecast proceeding ~~in the 2019 ERRA compliance and 2020 ERRA forecast proceedings~~.

4. It is reasonable to include ~~defer~~ in the PCIA calculation for this 2019 ERRA forecast proceeding a one-time adjustment in recognition of potential tax savings realized from application of the Tax Cut and Jobs Act ~~because they are not yet approved by the Commission~~.

5. A true-up of brown power ~~beginning in 2019~~ based on 2018~~9~~ market transactions would comply with Decision 18-10-019 and reflect the Commission's stated policy to enact a more accurate PCIA rate as soon as possible.

[*Alternative 1*] [X]. Revisions to the current ERRA framework should be considered in a Phase 2 of this proceeding that is consolidated with A.18-05-003 (Southern California Edison's 2019 ERRA forecast proceeding) and A.18-04-004 (San Diego Gas & Electric's 2019 ERRA forecast proceeding).

[*Alternative 2*] [X]. It is reasonable to require PG&E to include in its 2020 ERRA forecast application and proposed schedule (1) a planned workshop soon after the application is filed in which the utility will explain any significant changes in methodology or policy underlying the application, (2) use of the modified non-disclosure agreement from the PCIA proceeding R.17-06-026, (3) expedited discovery timelines, (4) a longer procedural schedule that still allows for a decision by January 1, 2020, (5) an update to the AET concurrent and consolidated with the November Update, and (6) a prehearing conference date prior to July 15, 2019.

Ordering Paragraphs

1. Pacific Gas and Electric Company's (PG&E) requests in Application 17-06-005 are adopted as follows: 1) adopt a forecast for the 2019 electric procurement revenue requirement of $2,907.4 million for PG&E, which consists of $1,554.0 million for the ERRA, $80.3 million for the Ongoing Competition Transition Charge, $~~1,142.0~~ $1,042 million for the Power Charge Indifference Adjustment , and $131.1 million for the Cost Allocation Mechanism; 2) approve PG&E's 2019 electric sales and peak load forecasts; 3) adopt a 2019 Greenhouse Gas (GHG)-related forecast of $1.083 million for administrative and outreach expenses pertaining to implementation of GHG allowance proceeds return, $324.5 million net forecast GHG revenue return amount; and adopts a 2019 semi-annual residential California Climate Credit of $29.18 per customer; 4) find 2017 recorded administrative and outreach expenses of $1.052 million pertaining to implementation of GHG allowance proceeds return, are reasonable; and, 5) approve PG&E's rate proposals associated with its electric procurement related revenue requirements to be effective in rates January 1, 2019.

2. PG&E must file a ~~Tier 1~~ Tier 2 Advice Letter within 30 days of the date of this decision (1) implementing a brown power true-up for the year 2018, (2) including a one-time adjustment for

the misallocation of CAM costs, (3) establishing a mechanism to apply anticipated tax savings to unbundled customers commensurate with that for bundled customers, and (4) conforming this decision's findings and conclusions to its final calculations, including the resulting tariff sheets, final PCIA revenue requirement and final Table 14-3 (listing the PCIA for each class within each vintage) that result from ~~in~~ compliance with each aspect of this decision.

[*Alternative 1*] [X]. Revisions to the current ERRA framework shall be considered in a Phase 2 of this proceeding that is consolidated with A.18-05-003 (Southern California Edison's 2019 ERRA forecast proceeding) and A.18-04-004 (San Diego Gas & Electric's 2019 ERRA forecast proceeding).

[*Alternative 2*] [X]. PG&E shall include in its 2020 ERRA forecast application and proposed schedule (1) a planned workshop soon after the application is filed in which the utility will explain any significant changes in methodology or policy underlying the application, (2) use of the modified non-disclosure agreement from the PCIA proceeding R.17-06-026, (3) expedited discovery timelines, (4) a longer procedural schedule that still allows for a decision by January 1, 2020, (5) an update to the AET concurrent and consolidated with the November Update, and (6) a prehearing conference date prior to July 15, 2019.

APPENDIX B

Table 14-3 (Compliant with Proposed Decision)
PROPOSED 2019 PCIA RATES ($/KWH)
Cost Responsibility Surcharge (CRS) Rates
2019 ERRA Forecast - November Update

Rate Group	DWR Bond (All Vintages)	ECRA (All Vintages)	CTC (For All Vintages)	Proposed PCIA Rates by Vintage 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	0.00549	(0.00001)	0.00102	0.02394	0.02722	0.02821	0.02917	0.02933	0.02934	0.02935	0.02919	0.02924	0.02932	0.02932
Small L&P	0.00549	(0.00001)	0.00102	0.02399	0.02728	0.02827	0.02923	0.02939	0.02941	0.02942	0.02926	0.02931	0.02939	0.02939
Medium L&P	0.00549	(0.00001)	0.00108	0.02531	0.02879	0.02983	0.03084	0.03101	0.03103	0.03104	0.03087	0.03093	0.03101	0.03101
E19	0.00549	(0.00001)	0.00098	0.02293	0.02607	0.02702	0.02794	0.02809	0.02811	0.02812	0.02797	0.02801	0.02809	0.02809
Streetlights	0.00549	(0.00001)	0.00083	0.01945	0.02212	0.02292	0.02370	0.02383	0.02385	0.02385	0.02372	0.02377	0.02383	0.02383
Standby	0.00549	(0.00001)	0.00074	0.01735	0.01973	0.02044	0.02114	0.02125	0.02127	0.02127	0.02116	0.02119	0.02125	0.02125
Agriculture	0.00549	(0.00001)	0.00092	0.02161	0.02457	0.02547	0.02633	0.02648	0.02649	0.02650	0.02636	0.02640	0.02647	0.02647
E20 T	0.00549	(0.00001)	0.00083	0.01953	0.02221	0.02302	0.02380	0.02393	0.02394	0.02395	0.02382	0.02386	0.02393	0.02393
E20 P	0.00549	(0.00001)	0.00089	0.02088	0.02374	0.02461	0.02544	0.02558	0.02559	0.02560	0.02546	0.02551	0.02558	0.02558
E20 S	0.00549	(0.00001)	0.00094	0.02204	0.02507	0.02598	0.02686	0.02701	0.02702	0.02703	0.02688	0.02693	0.02700	0.02700
System Average PCIA Rate by Vintage				0.02306	0.02622	0.02717	0.02810	0.02825	0.02827	0.02827	0.02812	0.02817	0.02824	0.02824

Table 14-3 (Compliant with Proposed Decision and 2018 Brown Power True Up)

PROPOSED 2019 PCIA RATES ($/KWH)

Cost Responsibility Surcharge (CRS) Rates

2019 ERRA Forecast - November Update

Rate Group	DWR Bond (All Vintages)	ECRA (All Vintages)	CTC (For All Vintages)	Proposed PCIA Rates by Vintage 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	0.00549	(0.00001)	0.00079	0.02087	0.02410	0.02503	0.02598	0.02614	0.02615	0.02615	0.02599	0.02604	0.02612	0.02612
Small L&P	0.00549	(0.00001)	0.00079	0.02091	0.02415	0.02509	0.02604	0.02620	0.02621	0.02621	0.02605	0.02610	0.02618	0.02618
Medium L&P	0.00549	(0.00001)	0.00083	0.02207	0.02548	0.02647	0.02748	0.02765	0.02765	0.02765	0.02749	0.02754	0.02762	0.02762
E19	0.00549	(0.00001)	0.00075	0.01999	0.02308	0.02398	0.02489	0.02504	0.02505	0.02505	0.02490	0.02495	0.02502	0.02502
Streetlights	0.00549	(0.00001)	0.00064	0.01696	0.01958	0.02034	0.02111	0.02124	0.02125	0.02125	0.02112	0.02116	0.02123	0.02123
Standby	0.00549	(0.00001)	0.00057	0.01513	0.01747	0.01814	0.01883	0.01895	0.01895	0.01895	0.01884	0.01887	0.01893	0.01893
Agriculture	0.00549	(0.00001)	0.00071	0.01884	0.02175	0.02260	0.02346	0.02360	0.02361	0.02361	0.02347	0.02351	0.02358	0.02358
E20 T	0.00549	(0.00001)	0.00064	0.01703	0.01966	0.02043	0.02120	0.02133	0.02134	0.02134	0.02121	0.02125	0.02131	0.02131
E20 P	0.00549	(0.00001)	0.00068	0.01820	0.02102	0.02184	0.02266	0.02280	0.02281	0.02281	0.02267	0.02272	0.02278	0.02278
E20 S	0.00549	(0.00001)	0.00072	0.01922	0.02219	0.02305	0.02393	0.02407	0.02408	0.02408	0.02393	0.02398	0.02405	0.02405
System Average PCIA Rate by Vintage				0.02010	0.02321	0.02411	0.02503	0.02518	0.02519	0.02519	0.02504	0.02509	0.02516	0.02516

Table 14-3 (Joint CCAs Proposals Less NSGBA Correction)
PROPOSED 2019 PCIA RATES ($/KWH)
Cost Responsibility Surcharge (CRS) Rates
2019 ERRA Forecast - November Update

				Proposed PCIA Rates by Vintage										
Rate Group	DWR Bond (All Vintages)	ECRA (All Vintages)	CTC (For All Vintages)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	0.00549	(0.00001)	0.00080	0.01920	0.02248	0.02343	0.02439	0.02455	0.02456	0.02456	0.02440	0.02445	0.02453	0.02453
Small L&P	0.00549	(0.00001)	0.00077	0.01863	0.02181	0.02273	0.02366	0.02382	0.02383	0.02383	0.02367	0.02372	0.02380	0.02380
Medium L&P	0.00549	(0.00001)	0.00080	0.01938	0.02268	0.02364	0.02461	0.02478	0.02478	0.02479	0.02463	0.02468	0.02476	0.02476
E19	0.00549	(0.00001)	0.00076	0.01827	0.02139	0.02229	0.02321	0.02336	0.02337	0.02337	0.02322	0.02327	0.02334	0.02334
Streetlights	0.00549	(0.00001)	0.00064	0.01546	0.01810	0.01887	0.01964	0.01977	0.01977	0.01978	0.01965	0.01969	0.01975	0.01975
Standby	0.00549	(0.00001)	0.00053	0.01291	0.01511	0.01575	0.01639	0.01650	0.01650	0.01651	0.01640	0.01643	0.01648	0.01648
Agriculture	0.00549	(0.00001)	0.00070	0.01680	0.01966	0.02050	0.02134	0.02148	0.02148	0.02149	0.02135	0.02139	0.02146	0.02146
E20 T	0.00549	(0.00001)	0.00064	0.01548	0.01812	0.01889	0.01966	0.01980	0.01980	0.01980	0.01967	0.01971	0.01978	0.01978
E20 P	0.00549	(0.00001)	0.00069	0.01659	0.01942	0.02024	0.02107	0.02121	0.02122	0.02122	0.02108	0.02112	0.02119	0.02119
E20 S	0.00549	(0.00001)	0.00073	0.01753	0.02053	0.02139	0.02227	0.02242	0.02242	0.02243	0.02228	0.02233	0.02240	0.02240
System Average PCIA Rate by Vintage				0.01816	0.02126	0.02216	0.02307	0.02322	0.02323	0.02323	0.02308	0.02313	0.02320	0.02320

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

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 18-06-001 (Filed June 1, 2018)

JOINT CCAS' REPLY COMMENTS ON PROPOSED DECISION

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Counsel to the Joint CCAs

December 24, 2018

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JOINT CCAS' REPLY COMMENTS ON PROPOSED DECISION

Pursuant to Rule 14.3, the Joint CCAs submit these reply comments on ALJ Wildgrube's PD regarding PG&E's ERRA Application.[1]

I. PG&E's Support for Never Truing Up 2018's Rates Harms Customers.

PG&E's support for the PD endorses never truing up the 2017 forecast that informed 2018's rates. No mechanism other than the true-up exists to make unbundled customers whole after making $109 million in overpayments in 2018. This result cannot be squared with the policy underlying the PCIA Decision, D.18-10-019, which ordered PG&E to true up brown power forecasts with actuals.

II. PG&E Agrees with the Joint CCAs: the PD's Math is Erroneous.

The Joint CCAs' Opening Comments establish $122.2 million in calculation errors in the PD if it is adopted with its current conclusions.[2] PG&E also "was unable to replicate" the $22 million reduction in the PD's PCIA revenue requirement ("RRQ"),[3] confirming the PD's numbers do not accurately reflect the PD's findings on forecasting sales or with regard to the "billing determinants" issue. In fact, PG&E suggests the latter should reduce the RRQ by $93 million, rather than the $88 million amount the Joint CCAs calculated, bringing the final RRQ down $127 million to $1,037 million.[4] PG&E also identifies a $6 million error in its November Update regarding "RPS sales revenue for the 2012 vintage."[5] The errors in the PD's calculations underscore the need for a Tier 2 Advice Letter to implement the PD. The advice letter should contain the final PCIA RRQ and final PCIA rates.

III. PG&E Cannot Create New Policy to Meet its Burden in an ERRA Proceeding.

PG&E cannot meet its burden to demonstrate its calculations and entries for the PCIA are "in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes" by proposing new rules and regulations.[6] ERRA forecast proceedings are limited to evaluating an IOU's compliance with prior Commission orders and rules.[7] Here, PG&E introduced two proposals for rules

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[1] Acronyms used herein have the same meaning as those in the Joint CCAs' Opening Comments on the PD.
[2] Joint CCAs Opening Comments on PD at 7-9.
[3] A.18-06-001, *PG&E's Comments on the Proposed Decision*, p. 7 (Dec. 17, 2018) ("PG&E Comments").
[4] PG&E Comments at p. 5, n. 8, p. 6, n. 10, and p. 7.
[5] *Id.* at p. 4, n. 5. It also makes no sense to adopt PG&E's suggestion to true up the $6 million error in the PABA when it can be addressed now. *Id.* The Joint CCAs' calculations already account for this error. *See* Joint CCAs Opening Comments on PD at 7-8, n. 26.
[6] *See* A.18-06-001, *Assigned Commissioner's Scoping Memo and Ruling*, p. 3 (Aug. 16, 2018).
[7] *See, e.g.*, D.18-01-009 at 10; A.13-05-015 Scoping Ruling, pp. 3-4 (September 12, 2013); A.17-06-005 Scoping Ruling, pp. 3-4 (August 24, 2017); A.18-06-001, *PG&E Reply to Protests and Responses*, pp. 2-3 (July 16, 2018); A.17-06-005, *Opening Brief of PG&E*, p. 21 (Oct. 16, 2017).

and regulations applying to the PCIA: (1) establishing a new methodology for forecasting multi-year sales of RA capacity, RPS-energy and brown power; and (2) proposing a new allocation methodology using non-system-level billing determinants. Both are far-reaching and not subject to input from affected stakeholders, and the PD properly declines to adopt them in an ERRA forecast proceeding.

A. The Record Strongly Supports Rejecting PG&E's Unsanctioned Sales Proposal.

The PD appropriately determines "[t]he sales of [RA] capacity and [RPS] eligible energy should be valued using the Market Price Benchmark" and deviating from this Commission-sanctioned approach would be improper within an ERRA proceeding.[8] Originally admitting no decision expressly allows for its proposal,[9] PG&E now stretches to argue its approach "is logical and consistent" with the PCIA Decision and "the purpose of the ERRA proceeding."[10] PG&E ignores how the PCIA Decision, D.18-10-019, does not rule on how these sales should be forecast in an ERRA proceeding or determine at which point in time, or at what value, anticipated revenues should become a part of customers' rates. It also ignores how the PCIA Decision specified a limited role for "actual recorded market transactions"[11] while the true-ups are being implemented—that of an *input* to the new benchmarks to estimate the Portfolio Market Value in the forecast year(s) that follow the sale.[12]

The PCIA Decision did *not* endorse an approach where the sale of some parts of a contract are directly netted from Total Portfolio Cost without considering the value of the parts of that contract that remain in the portfolio.[13] The PD rightly concludes "using something other than the market price benchmark to value PG&E's portfolio may not adequately account for benefits remaining with PG&E's bundled customers following sales of these products."[14] PG&E's assertions suggesting the transacted products "are no longer in the PCIA portfolio" and "cannot be used by bundled customers for any purpose" are unsupported by record evidence and, regardless, are incorrect.[15] PG&E is not assigning or selling the entire underlying contract, but rather multi-year strips of energy and capacity, meaning the contracts do not leave the portfolio, and benefits from the contracts continue to accrue to bundled

[8] Proposed Decision at 13, Conclusion of Law 2.
[9] Joint CCAs Opening Brief at 12-13 (citing Exh. Joint CCAs-4).
[10] PG&E Comments at 2.
[11] *Id.*
[12] Joint CCAs Reply Brief at 5-6 (citing to the adopted agenda version of D.18-10-019 at 73-74, 120-121, OP 1).
[13] *Id.* at 4-11 (citing the adopted agenda version of D.18-10-019 to explain how D.18-10-019 does not endorse PG&E's proposed methodology for the treatment of multi-year sales contracts).
[14] Proposed Decision at 13, Conclusion of Law 2.
[15] PG&E Comments at 2.

ratepayers, including values from hedging and compliance "buffers".[16] Indeed, these benefits are a key reason the Commission delayed setting the RA and RPS true-ups until Phase 2 in R.17-06-026, stating "the recorded 'actuals' do not reflect the untransacted capacity used for bundled customer compliance or the untransacted RECs either used for compliance or banked for future use."[17] The current proxy for the market value of *all* benefits from contracts that remain in the IOUs' portfolio is the relevant benchmark.[18] Failing to account for these benefits not only would prejudge Phase 2 of R.17-06-026, it would violate Pub. Util. Code §366.2(g).[19] Valuation at the benchmark is the only approach currently endorsed by Commission precedent,[20] and, therefore, is the approach that must be followed here.

Further, forecasting these transactions is much less straight-forward than PG&E leads the Commission to believe. PG&E's capacity sales are not associated with any particular unit until a few months before the relevant RA compliance deadlines, and PG&E can provide alternate capacity from a different unit.[21] RPS energy sales can be provided from any number of projects from different vintages within a specified portfolio.[22] Its hydroelectric sales may "come from one or more large hydroelectric facilities."[23] Without a direct linkage of a resource to a specific sale, and without a full specification of how the resources are to be dispatched by vintage, it cannot be determined whether the entire output from the specified portfolio will be sold with certainty nor what the exact mix of forecasted generation will be across vintages. As discussed extensively in prior filings,[24] this can lead to gaming, distortion and an extremely complex true-up that has to unwind this knot of forecasted and actual revenues with regard to every kWh or MW from every resource, every year. The PD's approach is better and much simpler: forecast these sales at the appropriate Commission-approved benchmark and then true them up later—in compliance with a future Commission *order* taking the final sales price into account.

B. D.18-10-019 Did Not Adopt PG&E's "Billing Determinants" Proposal.

"Rather than approving PG&E's new and unique modification" on how to allocate the PCIA, the PD rightly rejects it finding it "was not approved by D.18-10-019" and requires PG&E "to use the

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[16] Joint CCAs Opening Brief at 15, n. 16 (describing CalCCA's testimony in R.17-06-026).
[17] D.18-10-019 at 141.
[18] *See* D.11-12-018 at 8.
[19] Cal. Pub. Util. Code § 366.2(g) (stating "Estimated net unavoidable electricity costs … shall be reduced by the value of any benefits that remain with bundled service customers ….").
[20] Joint CCAs Opening Brief at 15 (citing Cal. Pub. Util. Code § 366.2(g) and D.11-12-018 at 8).
[21] Joint CCAs Reply Brief at 7 and n. 25 (citing to Exh. Joint CCAs-4 and the Advice Letters referenced therein).
[22] *Id.*
[23] Exh. Joint CCAs-12.
[24] *See, e.g.,* Joint CCAs Comments on November Update at 6-11.

system-level billing determinants consistent with its initial testimony."[25] PG&E disputes the PD's conclusion by relying, not on a conclusion of law or a finding of fact, but on one-third of one sentence in Section 9.2 in D.18-10-019.[26] However, as CLECA concedes,[27] Section 9.2 does not address this proposal. It only describes the current approach, stating "[t]he allocated costs are then divided by the rate group's total forecast system sales."[28] It then adopts a revision to a different part of the allocation process, *i.e.*, the change away from the "Top 100 Hours methodology." [29] Stretching further, PG&E suggests "Energy Division reviewed and approved the IOUs' updated PCIA templates," implying it approved the billing determinant methodology PG&E used.[30] D.18-10-019 did not delegate to Staff the ability to approve substantive rate design changes. In PG&E's own words, Staff's role was to review "a structural—*but non-substantive*—change to the PCIA Workpaper Template."[31] A non-substantive change would not result in a 7.6% increase to the average PCIA rate, as PG&E's proposal does.[32]

If PG&E believes the PCIA Decision should have included the "billing determinants" change, it should file a Petition for Modification of the PCIA Decision. The Joint CCAs also continue to support "a consolidated ERRA Phase 2 proceeding" to vet PG&E's ratemaking proposal for possible future use.[33] However, the Commission should not enact a half-baked ratemaking proposal, which itself creates distortions that require further fixes currently being implemented inconsistently across the IOUs,[34] in an ERRA forecasting proceeding solely intended to implement existing Commission rules.

IV. PG&E's Criticisms of the PD Have No Basis in the Record.

PG&E's comments should be accorded little weight because they contain almost no citations to the record,[35] meaning the issues raised therein are untested. For example, PG&E agues for its "billing determinants" proposal by suggesting the existing methodology was fine until departed load reached

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[25] Proposed Decision at 15-16.
[26] PG&E Comments at 4, n.6 (citing to D.18-10-019 at 124 and stating "For all these reasons, we find that the proposal made by the Joint Utilities in Exhibit IOU-1 should be adopted in this decision … ."). To be clear, the actual "proposal made by the Joint Utilities in Exhibit IOU-1" was the *clearly rejected* GAM/PMM proposal.
[27] CLECA Opening Comments at p. 2 ("…D.18-10-019 does not explicitly discuss this step….").
[28] D.18-10-019 at 122.
[29] *Id.* at 122-124.
[30] PG&E Comments at 4.
[31] Exh. PG&E-6, 7:10-13.
[32] Joint CCAs Comments on November Update at 12, n. 38.
[33] CLECA Comments at p. 3-4; *see also* Joint CCAs Comments on November Update at 23-24.
[34] *See* Joint CCAs Comments on November Update at 20-22. Further, PG&E appears to have incorrectly implemented its own proposal. *See id.* at 22-23.
[35] CPUC Rules of Practice and Procedure, Rule 14.3. PG&E's first record citation is in footnote 11 on p. 6.

20% of system sales but not when they reached 50%.[36] There is no testimony to support this assertion, and no discovery, cross-examination or rebuttal testimony to test it. We are simply left to wonder what happens at 50% that does not happen at 20%. The utility cannot use comments on a PD to repair its decision to keep its testimony as opaque as possible, to press for the shortest timelines possible, and to restrict the record as much as possible because there is no opportunity to test the assertions therein.

V. The True-Up and Cap Should Address Unintended Consequences, and PG&E's Footnote-Based Attempt to Modify D.18-10-019 Must be Rejected.

The true-up and cap (and associated trigger) in the new PCIA framework are intended to address under-collections that result from market changes or other factors in a timely manner and "ensure that bundled and departing load customers pay equally for PCIA-eligible resources."[37] Any under-collection would be captured by the true-up, and, if the cap is reached, such under-collections are tracked in an interest-bearing account and eventually recovered, addressing the oft-repeated concerns in PG&E's Opening Comments.[38] PG&E's rather astounding suggestion that the PD undermines its incentives to aggressively divest its long position ignores the utility's legal obligation to do so, suggests the utility needs incentives in order to follow the law, and should be disregarded.[39]

Finally, PG&E's footnoted suggestion that potential under-collections in a necessarily uncertain *forecast* proceeding somehow justify an exemption from the PCIA cap should be rejected as procedurally improper. [40] D.18-10-019 does not establish the possibility for exemptions to the cap, and it cannot be modified via a footnote in comments on a PD in another proceeding. More importantly, no need for any exemptions exists because all costs above the cap will be recovered in a timely manner.[41]

VI. Conclusion

We respectfully request the PD be revised per Appendix A to the Joint CCAs' Opening Comments, updated to reflect PG&E's $93 million RRQ reduction and a final RRQ of $1,037 million.

Dated: December 24, 2018

Respectfully submitted,

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[36] PG&E Comments at 5 and n. 7.
[37] *See, e.g.,* D.18-10-019 at 72, Conclusions of Law 16-17 and 19-24, and Ordering Paragraphs 9-10.
[38] *Id.*; PG&E Comments at p. 3, and n. 3 and 4, and pp. 5-7, and n. 8 and 10.
[39] PG&E Comments at 4; Cal Pub Util Code §§ 365.2, 366.2(f)(2).
[40] CPUC Rules of Practice and Procedure, Rule 16.1(c); PG&E Comments at 6, n. 10.
[41] *See, e.g.,* D.18-10-019 at 72, Conclusions of Law 16-17 and 19-24, and Ordering Paragraphs 9-10.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

PREHEARING CONFERENCE STATEMENT OF PENINSULA CLEAN ENERGY, MARIN CLEAN ENERGY AND SONOMA CLEAN POWER

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

PREHEARING CONFERENCE STATEMENT OF
PENINSULA CLEAN ENERGY, MARIN CLEAN ENERGY AND
SONOMA CLEAN POWER

Pursuant to Administrative Law Judge ("ALJ") Roscow's November 29, 2018 Ruling Setting Prehearing Conference ("PHC"), Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), and Peninsula Clean Energy Authority ("PCE") (collectively, the "NorCal CCAs") submit this PHC Statement.[1] As noted below, the NorCal CCAs support the positions put forth by the California Community Choice Association ("CalCCA") in its PHC Statement.

Legal deficiencies in D.18-10-019 argue for the Commission utilizing Phase 2 of this proceeding to determine (1) whether costs included in the Power Charge Indifference Adjustment ("PCIA") to date were avoidable and/or were not attributable to departed customers and (2), if so, how an appropriate recompense should be structured, including whether such recompense should come from utility shareholders.[2] While this issue could be addressed in the Portfolio Optimization and Cost Reduction working group,[3] we explain below why resolving the

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1 *Administrative Law Judge's Ruling Setting Prehearing Conference*, p. 1 (Nov. 29, 2018).

2 The NorCal CCAs filed an Application for Rehearing of D.18-10-019 that addresses this legal deficiency. Therein, we request the Commission "either: 1) address whether the IOUs incurred unavoidable costs and took all reasonable steps to minimize above-market costs before establishing a new PCIA; or, 2) at the very least, ensure that parties may further continue in Phase 2 of this proceeding to identify the extent to which the costs incurred by the IOUs to date are illegitimate and avoidable." R.17-06-026, *Application for Rehearing of Peninsula Clean Energy Authority, Marin Clean Energy, and Sonoma Clean Power Authority of D.18-10-019*, p. 3, (Nov. 19, 2018) ("NorCal CCAs AFR").

3 CalCCA proposes that this working group be combined with the Allocation and Auction working group, and the NorCal CCAs agree.

question likely will prove to be ill-suited for a working group process and will likely require hearings due to its contentious nature. For that reason, the NorCal CCAs propose a separate track in Phase 2 to allow investigation of and appropriate adjustments to the PCIA resulting from problematic forecasting and portfolio mismanagement in the past. A separate track will facilitate adequate attention to the issue without slowing progress on more collaborative work addressing forward-looking questions. A schedule is proposed for this separate track in Attachment B. Phase 2 of this proceeding should be classified as ratesetting.

I. Phase 2 Should Determine Whether the Current PCIA Includes Avoidable Costs Inappropriately Attributed to Unbundled Customers.

The Scoping Ruling states the final PCIA "should only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs."[4] It includes as an issue whether the Commission should "require and verify optimization of IOU portfolio management (*e.g.*, contract extensions and contract renegotiation) in order to minimize above-market costs."[5] Rather than squarely addressing this issue in what has become Phase 1, which the Commission's statutory obligations require, D.18-10-019 initiates a second phase "to develop structures, processes, and rules governing portfolio optimization *going forward*."[6] Among other things,

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4 *Scoping Memo and Ruling of Assigned Commissioner* ("Scoping Ruling"), p. 14, Guiding Principle 1.h. (Sept. 25, 2017).

5 Scoping Ruling at 20, Issue 6.

6 *Decision Modifying the Power Charge Indifference Adjustment Methodology* ("D.18-10-019"), p. 11 (Oct. 19, 2018). (emphasis added); Finding of Fact 27 (stating "A new phase of this proceeding would enable parties to continue working together to develop a number of proposals regarding portfolio optimization and cost reduction for future consideration by the Commission."); Conclusion of Law 26 (stating "A second phase of this proceeding should be opened in order to consider proposals for a "working group" process to enable parties to continue working together to develop proposals regarding portfolio optimization and cost reduction for future consideration by the Commission."); Ordering Paragraph 14 (stating "A second phase of this proceeding is opened to establish a "working group" process to enable parties to further develop a number of proposals for future consideration by the Commission. A prehearing conference shall be scheduled to initiate that process.").

Phase 2 "will consider shareholder responsibility for *future* portfolio mismanagement, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards."[7]

While the NorCal CCAs support addressing these issues in Phase 2, the forward-looking limitation the Commission appears to set for this Phase creates a gap in the Commission's consideration of the PCIA that the law does not allow. "Utilities are of course required to manage their portfolios prudently,"[8] and Sections 365.2 and 366.2(f)(2) of the Public Utilities Code ("PU Code") require the Commission to ensure the PCIA does not include avoidable costs or costs that should not be attributed to departing load.[9]

Instead of addressing whether the PCIA meets this legal standard, D.18-10-019 errs by ignoring clear record evidence of past portfolio mismanagement,[10] and excluding any findings of

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7 D.18-10-019 at 112 (emphasis added).

8 *Id*.

9 Cal Pub Util Code § 365.2 (stating "The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs ***that were not incurred on behalf of the departing load***.") (emphasis added); Cal Pub Util Code § 366.2(f)(2) (stating "A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following … any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's ***estimated net unavoidable electricity purchase contract costs*** attributable to the customer, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.") (emphasis added).

10 For example, the original Proposed Decision of ALJ Roscow emphasized that "[t]he record in this proceeding clearly demonstrates that… the Joint Utilities have not made a convincing showing regarding what actions, if any, they have taken since 2004 to comply with the Commission directives …." R.17-06-026, *Proposed Decision of ALJ Roscow Modifying the Power Charge Indifference Adjustment Methodology*, p. 62 (Aug. 1, 2018); *see also* NorCal CCAs AFR at 10-15 (detailing numerous instances in the record providing a reasonable basis to conclude the IOUs were responsible for imprudent management of their generation portfolios that created significant above-market costs to the detriment of all ratepayers by, among other thing, ignoring imminent load departures, failing to manage to imminent load departures, and/or suggesting it would take load departures of greater than 10-20% before a utility would make any portfolio adjustments.).

fact or conclusions of law regarding whether the IOUs incurred legitimately unavoidable costs and took all reasonable steps to minimize above-market costs.[11] If the Commission declines to address these errors in response to the NorCal CCAs' Application for Rehearing ("AFR"), submitted on November 19, 2018, it should take up this issue in Phase 2 of this proceeding in order to fulfill its statutory mandate. The Commission would err again by failing to do so.

To be clear, the NorCal CCAs are *not* requesting "a secondary, after-the-fact reasonableness review of the previously-approved costs of specific resource" procurement decisions.[12] On the contrary, the NorCal CCAs are advocating for a statutorily required review that necessarily must take place *after* initial approval of specific resources. The utilities have repeatedly and inappropriately attempted to conflate reasonableness with unavoidability/attributability to suggest the Commission has already addressed these critical issues. They argue "the question of whether resource costs are 'avoidable' is made at the time the resource cost is approved by the Commission, and through the Joint Utilities' respective ERRA Review proceedings."[13] While imprudent management "would justify disallowing recovery of portfolio costs, and *could* be considered in ERRA or General Rate Case (GRC) proceedings,"[14] the fact is that the utilities have expressly argued against such considerations from being in scope in the ERRA proceedings, and the Commission has acquiesced by narrowly limiting the scope of these proceedings.

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[11] *See* NorCal CCAs AFR at 4-7, 10-15.

[12] *Response of Pacific Gas and Electric Company (U 39-E), Southern California Edison Company (U 338-E), and San Diego Gas & Electric Company (U 902-E) to Applications for Rehearing of Decision 18-10-019* ("IOUs' Response to AFRs") at p. 26 (Dec. 4, 2018).

[13] *Id.* at 25.

[14] D.18-10-019 at 112 (emphasis added).

A procurement decision is "based on the best information available at the time."[15] It is not a question of avoidability. As noted in CalCCA's testimony in Phase 1, "[t]he existence of a resource in the utility portfolio - even if the initial decision to procure it was prudent given the information available at that time - does not alleviate the utility of their responsibility to actively manage those resources to the benefit of all customers."[16] Many subsequent decisions affect the ongoing portfolio composition based on new information regarding market developments and changes in demand.[17] Thus, the procurement decision itself is insufficient to address unavoidability.

The suggestion that the utilities address these issues "annually in the ERRA Review proceedings, and submit extensive evidence demonstrating the reasonableness of their portfolio management activities in this proceeding"[18] contradicts prior utility arguments. In A.18-02-015, PG&E argued that prudence review should not be in scope for the ERRA compliance proceeding.[19] It later clarified that "the question of whether PG&E prudently administered and managed its QF and non-QF contracts in accordance with the contracts' provisions is within the scope of the proceeding. But that issue does not encompass either of the issues raised by SCP, ***portfolio management and load forecasting***."[20]

The Commission unfortunately has approved of PG&E's arguments and limited the scope of both the ERRA forecast and compliance proceedings. The NorCal CCAs' AFR details a recent history of PG&E's ERRA process that showcases CCAs' and other stakeholders' inability

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15 *Id.* at 106 (citing AReM/DACC's comments, which cite Ex. CalCCA-01, at 2A-5).
16 *Id.*
17 *Id.*
18 IOUs' Response to AFRs at 29.
19 NorCal CCAs AFR at 8-10.
20 A.18-02-015, Reply of PG&E to Protests to the Application, pp. 5, 7 (April 16, 2018).

to find a venue to address billions of dollars in PG&E procurement costs.[21] That timeline describes how parties first sought review of IOU portfolio management in the ERRA forecast docket, but were told to await the ERRA compliance docket.[22] When the same parties then sought review of IOU portfolio management in the ERRA compliance docket, the Commission told parties that such a review was more appropriate for a general rate case or a separate application proceeding.[23]

The utilities have not and cannot point to a Commission decision that includes a finding of fact or conclusion of law that the costs remaining in the IOUs' portfolio are unavoidable across the board and are appropriately attributable to departing load because, to the NorCal CCAs' knowledge, no such Commission decision exists. The NorCal CCAs respectfully request the Commission end this "wild goose chase" and address these statutory provisions in this proceeding, either via the NorCal CCAs' AFR and/or via a separate track in Phase 2.

II. Questions Regarding the "Avoidable and Attributable" Components of the Portfolios are Ill-Suited to a Working Group Process.

As noted above, D.18-10-019 includes these questions of unavoidability and attributability within Phase 2 on a going-forward basis. We agree those are critical questions and support their discussion in the Portfolio Optimization and Cost Reduction working group.[24] However, an examination of whether resources procured to date that are currently in IOUs' portfolios were avoidable and appropriately attributed to departing load based on reasonable load forecasting is likely too contentious of an issue for the working group process. The NorCal CCAs do not envision the IOUs will agree this issue should be in scope for Phase 2 and will not

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21 NorCal CCAs AFR at 8-10.
22 *Id.*
23 *Id.*
24 CalCCA proposes that this working group be combined with the Allocation and Auction working group, and the NorCal CCAs agree.

agree it is something to which they should be held accountable, let alone that they will cooperate on discovery and collaborate with the NorCal CCAs and other parties. Further, the issue is likely to require legal briefing, hearings, and cross examination to address. Thus, the NorCal CCAs recommend the Commission initiate a separate track to address these questions so as not to delay progress on subject matters more conducive to collaboration.

Finally, with regard to specific questions included in the ALJ's PHC Ruling, the NorCal CCAs respond as follows:

- The NorCal CCAs support the number and scope of working groups included in CalCCA's PHC Statement;
- The NorCal CCAs have attached a table hereto as Attachment A that quotes and cites each of their recommendations for Phase 2, matched to the working groups listed in the PHC Ruling, including the recommended "unavoidable and attributable" issues discussed above;
- The NorCal CCAs support the governance and ground rules for each working group included in CalCCA's PHC Statement;
- The NorCal CCAs support the provisions in CalCCA's PHC Statement regarding working groups producing timely, actionable recommendations;
- The NorCal CCAs do not believe a single "kick-off" workshop for the purpose of forming each of the working groups is necessary but do not oppose one;
- The NorCal CCAs support the recommended schedule put forth by CalCCA that would allow a proposed decision addressing the recommendations of each working group to be issued in September 2019;
- The Joint CCA recommend a schedule in Attachment B to address the separate track for the "unavoidable and attributable" issues the NorCal CCAs raise in this PHC Statement; and
- The NorCal CCAs support the prioritization of working groups included in CalCCA's PHC statement.

III. Phase 2 Procedures Should Ensure Parties the Opportunity to Build a Complete Record.

In-depth consideration of the IOUs' past efforts to minimize costs will require the parties to build a complete record on which the Commission can make a clear and final ruling. To this end, the NorCal CCAs believe evidentiary hearings are necessary in Phase 2 to address the following material, contested issues of fact:

- The precise identification of which IOU procurement commitments have been attributed to CCA customers, but were made with knowledge of CCA departing load and with no accompanying change to the procurement plans to account for those departures;
- What actions, if any, the utilities have taken since 2004 to comply with Commission directives to manage their portfolios in a manner that reduces above-market costs and avoids procurement in the face of imminent departing load;
- The extent to which the IOUs' own efforts undermined CCA implementation plans and thwarted imminent departures in San Joaquin Valley and other areas of the State;
- How PG&E reconciles statements that they would not have changed procurement until 10 to 20% of load has departed with continuing to attribute resources subsequently purchased to the NorCal CCAs; and
- Other contested, material issues of fact that are likely to come to light over the course of the proceeding.

This proceeding should be categorized as ratesetting because it will materially affect the PCIA, a rate that appears on each CCA customer's bill. The *ex parte* requirements for ratesetting further support such a determination. The parties' ability to reduce the above-market costs within each IOUs' portfolio is a critical component of the continuing viability of CCAs and other retail choice providers. The gravity of these issues to the State, CCAs, electric service providers and ratepayers warrants a substantial degree of transparency with regard to communications between Commission decision-makers and entities interested in the outcome of this docket. A ratesetting designation will help to ensure such transparency.

Finally, the NorCal CCAs and CalCCA experienced difficulty in obtaining timely and detailed responses to discovery, particularly concerning questions surrounding the IOUs' procurement and forecasting strategies in light of substantial departing load. We anticipate these are issues on which the utilities will be unwilling to cooperate in Phase 2. For that reason, the NorCal CCAs request a clear determination in the Scoping Ruling that past portfolio management and forecasting are within scope of Phase 2 and that the Commission will require timely and responsive answers to data requests on those issues. Further, to better understand the factors influencing IOU actions on CCA departing load, the Phase 1 non-disclosure agreement also should be used for discovery in Phase 2.

IV. Conclusion

The NorCal CCAs appreciate the opportunity to provide input on the scope of Phase 2 and look forward to working with the utilities and other parties to address the issues included therein.

Respectfully submitted,

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Dated: December 12, 2018

Attachment A

Summary of the Prior Comments on the Scope of Phase 2 of PCE, MCE and SCP

Party	Phase II Proposal	Reference	Applicable Working Group / Track
Peninsula Clean Energy	Investigate more reliable, verified data regarding the value of long-term capacity benefits.	Opening Comments of Peninsula Clean Energy Authority on Alternate Proposed Decision of Commissioner Peterman[25] at 3, 8	Portfolio Optimization and Cost Reduction /Allocation and Auction
Peninsula Clean Energy	Establish mechanisms to reduce the IOUs' oversized portfolios, create cost savings for both bundled and unbundled customers, and use the data from those mechanisms to better inform the components of the market price benchmark.	PCE Comments on APD at 13	Portfolio Optimization and Cost Reduction /Allocation and Auction
Peninsula Clean Energy	Examine the extent of above-market resource procurement costs created by IOUs' forecasts of departed load due to CCAs.	PCE Comments on APD at 15-16	"Unavoidable and Attributable" Track Addressed Herein
Peninsula Clean Energy	Explore what mechanisms can be implemented to make clear the market value of IOUs' long-term capacity contracts (e.g., conducting voluntary auctions of existing contracts).	PCE Comments on APD at 17	Portfolio Optimization and Cost Reduction /Allocation and Auction

[25] *Opening Comments of Peninsula Clean Energy Authority on Alternate Proposed Decision of Commissioner Peterman* ("PCE Comments on APD") filed September 6, 2018.

Party	Phase II Proposal	Reference	Applicable Working Group / Track
Peninsula Clean Energy	Identify, with precision, the IOU procurement commitments that have been attributed to CCA customers, but were made with knowledge of CCA departing load and with no accompanying change to the procurement plans to account for those departures.	PCE Comments on APD at 18-19	"Unavoidable and Attributable" Track Addressed Herein

Party	Phase II Proposal	Reference	Applicable Working Group / Track
Marin Clean Energy	Address and correct deficient IOU forecasting practices for CCA departed load.	Marin Clean Energy's Comments on the Proposed Decision of ALJ Roscow Modifying the Power Charge Indifference Adjustment Methodology at 2 ("MCE Comments on PD"); [26] Marin Clean Energy's Comments on the Alternate Proposed Decision of Commissioner Carla J. Peterman to the Proposed Decision of Administrative Law Judge Stephen C. Roscow Modifying the Power Charge Indifference Adjustment Methodology at 2("MCE Comments on APD"); [27]	CalCCA-proposed Forecasting Working Group

[26] *Marin Clean Energy's Comments on the Proposed Decision of ALJ Roscow Modifying the Power Charge Indifference Adjustment Methodology* ("MCE Comments on PD") filed August 21, 2018.
[27] *Marin Clean Energy's Comments on the Alternate Proposed Decision of Commissioner Carla J. Peterman to the Proposed Decision of Administrative Law Judge Stephen C. Roscow Modifying the Power Charge Indifference Adjustment Methodology* ("MCE Comments on APD") filed September 6, 2018.

Party	Phase II Proposal	Reference	Applicable Working Group / Track
Marin Clean Energy	Identify, with precision, the IOU procurement commitments that have been attributed to CCA customers, but were made with knowledge of CCA departing load and with no accompanying change to the procurement plans to account for those departures.	MCE Comments on PD at 3; MCE Comments on APD at 3	"Unavoidable and Attributable" Track Addressed Herein
Marin Clean Energy	Develop a probabilistic approach to forecast CCA departing load and a scenario-based assessment of potential long-term load departures to appropriately capture future CCA load departures and mitigate the potential for excess utility resources and increased costs.	MCE Comments on PD at 4, 11; MCE Comments on APD at 4, 11	CalCCA-proposed Forecasting Working Group
Marin Clean Energy	Resolve unlawful IOU forecasting practices for departed load and resulting cost shifts to CCA customers.	MCE Comments on PD at 10; MCE Comments on APD at 11	"Unavoidable and Attributable" Track Addressed Herein

Party	Phase II Proposal	Reference	Applicable Working Group / Track
Marin Clean Energy	Ensure that forecasted departing load is not attributed cost responsibility for contracts executed in a certain year up to the amount of departed load forecast for that year.	MCE Comments on PD at 12; MCE Comments on APD at 12	"Unavoidable and Attributable" Track Addressed Herein
Marin Clean Energy	Improve accuracy of departing load forecasting.	Marin Clean Energy's Reply to Comments on the Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology & the Alternate Proposed Decision of Commissioner Carla J. Peterman to the Proposed Decision of Administrative Law Judge Stephen C. Roscow Modifying the Power Charge Indifference Adjustment Methodology[28] at 2	CalCCA-propsed Forecasting Working Group

[28] *Marin Clean Energy's Reply to Comments on the Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology & the Alternate Proposed Decision of Commissioner Carla J. Peterman to the Proposed Decision of Administrative Law Judge Stephen C. Roscow Modifying the Power Charge Indifference Adjustment Methodology* ("MCE Reply Comments on PD and APD") filed September 13, 2018.

Party	Phase II Proposal	Reference	Applicable Working Group / Track
Marin Clean Energy	Identify and resolve cost-shifts to CCA customers resulting from IOUs' failure to forecast CCA departing load, particularly in early years of CCA formation.	MCE Reply Comments on PD and APD at 2, 4	"Unavoidable and Attributable" Track Addressed Herein
Marin Clean Energy	Identify the extent to which past IOU forecasting decisions resulted in over-procurement and avoidable above-market costs being assigned to CCA customers through the PCIA.	MCE Reply Comments on PD and APD at 4-5	"Unavoidable and Attributable" Track Addressed Herein
Marin Clean Energy	Identify reasonable ways for the IOUs to obtain the information they need to adequately forecast future CCA departing load and mitigate future forecasting inaccuracies.	MCE Reply Comments on PD and APD at 5.	CalCCA-proposed Forecasting Working Group
Sonoma Clean Power	Require the implementation of portfolio sales and reverse auctions.	Opening Comments of Sonoma Clean Power Company on ALJ Roscow's Track 2 Proposed Decision[29] at 3	Portfolio Optimization and Cost Reduction /Allocation and Auction

[29] *Opening Comments of Sonoma Clean Power Company on ALJ Roscow's Track 2 Proposed Decision* ("SCPA Comments on PD") filed August 21, 2018.

Party	Phase II Proposal	Reference	Applicable Working Group / Track
Sonoma Clean Power	Define “indifference” in a manner than establishes up-front values and standards to create a level playing field amongst each customer group.	SCPA Comments on PD at 10; Reply Comments of Sonoma Clean Power Authority on ALJ Roscow’s Track 2 Proposed Decision and Commissioner Peterman’s Alternate Proposed Decision[30] at 4.	Portfolio Optimization and Cost Reduction /Allocation and Auction
Sonoma Clean Power	Address IOUs’ lack of active portfolio management by developing a common problem statement.	SCPA Reply Comments on PD and APD at 3.	Portfolio Optimization and Cost Reduction /Allocation and Auction
Sonoma Clean Power	Define “good faith negotiations” in the context of addressing and negotiating pre-payment options for departed load customers.	SCPA Reply Comments on PD and APD at 4	Prepayment
Sonoma Clean Power	Evaluate IOU portfolio management.	SCPA Reply Comments on PD and APD at 7	“Unavoidable and Attributable” Track Addressed Herein and Portfolio Optimization and Cost Reduction /Allocation and Auction

[30] *Reply Comments of Sonoma Clean Power Authority on ALJ Roscow’s Track 2 Proposed Decision and Commissioner Peterman’s Alternate Proposed Decision* (“SCPA Reply Comments on PD and APD”) filed on September 13, 2018.

Attachment B – Proposed Schedule for Separate Track of Phase 2

Phase 2 – “Unavoidable and Attributable” Track	**Proposed Date**
Prehearing Conference	December 19, 2018
Commissioner’s Scoping Ruling Issued	January 16, 2019
Concurrent Direct Testimony	March 22, 2019
Concurrent Rebuttal Testimony	April 26, 2019
Evidentiary Hearings	May 20-24, 2019
Opening Briefs	June 25, 2019
Reply Briefs	July 12, 2019
Proposed Decision	August 2019
Final Decision	September 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 18-06-001 (Filed June 1, 2018)

COMMENTS IN RESPONSE TO ALJ RULING OF 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

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January 4, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 18-06-001 (Filed June 1, 2018)

COMMENTS IN RESPONSE TO ALJ RULING OF 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

Pursuant to Administrative Law Judge ("ALJ") Wildgrube's December 27, 2018 ruling ("ALJ Ruling"), 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 ("CCAs"), submit these comments on corrections to certain errors included in the proposed decision issued December 7, 2018 ("Proposed Decision" or "PD") on Pacific Gas & Electric Company's ("PG&E") above-captioned Energy Resource and Recovery Account ("ERRA") Application.[1] "These errors appear in the table on page 2 of the [PD] and are repeated elsewhere in the decision." [2]

The Joint CCAs appreciate the opportunity to submit these comments on two notable findings and conclusions within the PD: "continuing valuation using the market price benchmark of RA capacity and RPS positions and continuing use of system-level billing determinates when

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1 A.18-06-001, *E-mail Ruling of ALJ Wildgrube* (Dec. 27, 2018) ("ALJ Ruling").
2 *Id.*

modifying revenue allocation factors consistent with PG&E's initial testimony."[3] The ALJ Ruling requires the Joint CCAs to file comments confirming or correcting revised amounts for the Power Charge Indifference Adjustment ("PCIA") Revenue Requirement, which the ruling includes in the following table:[4]

Revenue Requirements	2019 Cost with FF&U Net of GTSR Program Cost	Year-End 2018 Balance	PCIA	PCIA Sub-account	Total 2019 Revenue Requirements
ERRA	$ 2,696,558,120	$ (508,133)	$ (1,042,892,751)	$ (5,304,645)	$ 1,647,852,591
Ongoing CTC (i.e., MTCBA)	67,405,765	12,885,488			80,291,253
CAM Charge (i.e., NSGBA)	157,440,102	(26,366,744)			131,073,358
PCIA			1,042,892,751	5,304,645	1,048,197,396
Total	**$ 2,921,403,986**	**$ (13,989,388)**	**$ -**	**$ -**	**$ 2,907,414,598**

The Joint CCAs confirm they are able to reproduce numbers set forth in the table above. The difference between the figures in the Joint CCAs' Opening Comments on the PD and the above table is composed of a correction to the 2012 vintage of PG&E's RPS sales and a difference in how Resource Adequacy ("RA") and Renewable Portfolio Standard ("RPS") sales are valued in the calculation. Whereas the Joint CCAs zeroed out the sales in the workpapers, the ALJ Ruling's figures reset the value of those sales to the appropriate market price benchmarks. The difference arises in how the line losses are valued, and the ALJ Ruling uses an appropriate approach.

Also, the ALJ Ruling adopts the same $88 million reduction[5] from the revenue requirement shown in the November Update in order to implement the billing determinants issue that the Joint CCAs calculated, which, notably, PG&E itself calls a "*proposal* to use billing

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3 *Id.*
4 *Id.*
5 Joint CCA Comments, p. 9, n. 35.

determinants based on departed load."[6] This amount is different than the $93 million figure PG&E offers in its Opening Comments,[7] or the "over $180 million" estimate PG&E describes in its Reply Comments.[8] Since PG&E does not explain how it derived either of these two figures, the Joint CCAs are unable to determine which is more accurate, or whether one or the other, or neither, should replace the $88 million figure in the calculations underlying the ALJ Ruling.

The starkly different figures PG&E has presented regarding the impact of the PD warrant careful consideration to ensure the resulting rates are accurate, just and reasonable. Further, PG&E's November Update used the allocation factors in its Annual Electric True-Up Advice Letter, rather than those from its 2017 General Rate Case ("GRC").[9] This change appears to further alter the PCIA revenue requirement significantly, and the Joint CCAs wish to have the opportunity to review this implementation step. The Joint CCAs believe the best course to ensure these results is to require PG&E to file a Tier 2 Advice Letter implementing the PD by (1) conforming its calculations to the final decision's findings and conclusions and (2) calculating and showing the results of (a) the final PCIA revenue requirement, (b) the final Table 14-3 (listing the PCIA for each class within each vintage) and (c) the final ERRA revenue requirement, *i.e.*, the bundled generation revenue requirement.

We respectfully request the Commission revise the PD to include such a requirement in addition to the other revisions enumerated in the Joint CCAs' Opening and Reply Comments, and we again thank Commission Staff and ALJ Wildgrube for their on-going efforts to resolve the complex issues raised in this docket in an expeditious manner.

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6 PG&E Reply Comments at 1 (emphasis added).

7 PG&E Comments at p. 5, n. 8, p. 6, n. 10, and p. 7.

8 PG&E Reply Comments at 4.

9 Exh. PG&E-6, 6:25 to 7:1; Exh. Joint CCAs-14. The Annual Electric True-Up allocation factors are stale, being based on PG&E's 2014 GRC.

Dated: January 4, 2019

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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.	R.16-02-007 (Filed February 11, 2016)

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON RULING SEEKING COMMENT ON POLICY ISSUES AND OPTIONS RELATED TO RELIABILITY

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January 14, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007 (Filed February 11, 2016)

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON RULING SEEKING COMMENT ON POLICY ISSUES AND OPTIONS RELATED TO RELIABILITY

Pursuant to the directions set forth in the *Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability* ("Joint Ruling") issued on November 16, 2018, the California Community Choice Association ("CalCCA") respectfully submits the following reply comments on the Joint Ruling. Numerous issues were raised in parties' opening comments and CalCCA does not attempt to address every issue raised. Instead, CalCCA highlights areas of agreement between parties as a starting point for next steps on the questions raised in the Joint Ruling. CalCCA also corrects and clarifies certain parties' mischaracterizations of the Integrated Resource Plan ("IRP") filings of Community Choice Aggregators ("CCAs").

As discussed in CalCCA's opening comments, the Proposed Decision in the Commission's current Resource Adequacy proceeding ("RA PD") could have a substantial impact on the questions raised in the Joint Ruling and create disruption and uncertainty the RA market.[1] The potential consequences of the RA PD cannot be ignored in considering the questions raised in the Joint Ruling, particularly since the Joint Ruling and the RA PD both seem to seek to address possible near- and

[1] *Comments of California Community Choice Association on Ruling Seeking Comment on Policy Issues and Options Related to Reliability*, at 4, 6 (December 20, 2018) ("CalCCA Opening Comments"). See also, *Comments of the Alliance for Retail Energy Market on Policy Issues and Options Related to Reliability*, at 6 (December 20, 2018), *Comments of San Diego Gas & Electric Company in Response to Ruling Seeking Comment on Policy Issues and Options Related to Reliability*, at 5 (December 20, 2018).

medium-term reliability challenges. Therefore, CalCCA requests the opportunity to submit additional comments on the Joint Ruling once a decision is approved in the RA proceeding.

Related to the impact of the RA PD is the issue raised by CalCCA and other parties regarding coordination of proceedings before the California Public Utilities Commission ("Commission") and coordination between Commission proceedings and stakeholder initiatives at the CAISO.[2] There was broad agreement between parties that there must be better inter-agency coordination between the Commission and CAISO.[3] Many parties also agreed that there needs to better coordination between the Commission's own proceedings relating to reliability. For example, in response to Question 2 of the Joint Ruling regarding whether the RA or the IRP proceeding is the appropriate forum to address possible near- or medium-term reliability concerns, most parties responded that both proceedings are appropriate because of the differing time horizons for, and issues to be considered in both proceedings.[4] While CalCCA believes that the RA proceeding is the appropriate proceeding to consider and address possible reliability concerns, it agrees with parties that both proceedings must be closely coordinated by the Commission.

Although CalCCA believes strongly that Commission proceedings relating to reliability should be coordinated, it also notes that the issues within the scope of each Commission proceeding must be clear so as to prevent unnecessary and burdensome overlap between related, but separate proceedings. For example, proposals addressing RA requirements and compliance with those requirements[5] are more appropriately addressed in the RA proceeding. Whereas, as noted in the opening comments of

[2] CalCCA Opening Comments, at 5-7.

[3] See *Comments on Ruling of the Department of Market Monitoring of the California Independent System Operator Corporation*, at 1-3 (December 20, 2018), *Comments of Environment Defense Fund on Policy Issues and Options Related to Reliability*, at 8-9 (December 20, 2018), *Opening Comments of Pacific Gas and Electric Company on Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability*, at 10 (December 20, 2018) ("PG&E Opening Comments").

[4] See *Comments of the California Large Energy Consumers Association on the Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability*, at 6 (December 20, 2018), *Opening Comments of the Union of Concerned Scientists on the Ruling Seeking Comment on Policy Issues and Options Related to Reliability*, at 3-4 (December 19, 2018), *Opening Comments of the Public Advocates Office in Response to Joint Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability*, at 3-4 (December 20, 2018) ("PAO Opening Comments").

[5] See PG&E Opening Comments, at 17.

several parties, the IRP proceeding is for planning.[6] While the RA and IRP proceedings should be closely aligned, the scope and issues within each proceeding should be clear in order to avoid redundant, repetitive, or inconsistent obligations on parties in both proceedings.

Finally, CalCCA would like to correct several fundamental mischaracterizations of CCAs' IRP filings made by certain parties. For instance, Southern California Edison ("SCE") questions CCAs' commitment to fully participating in the Commission's IRP process and whether CCAs' IRP filing represent their actual resource planning.[7] In addition, Pacific Gas and Electric ("PG&E") states that CCA plans failed to address reliability needs and resources.[8]

As stated in CalCCA's comments on Load Serving Entities' ("LSEs") Integrated Resource Plans, all operational members of CalCCA filed Integrated Resource Plans[9] and fully intend to comply with statutory requirements as well as the directives in Commission Decision (D.) 18-02-018.[10] Further, all CCAs are projected to meet their GHG emissions benchmarks and RPS requirements, and have demonstrated diligence in complying with applicable RA requirements.[11]

With respect to RA requirements and resources, guidance provided on IRP filing requirements made it clear that:

> In the near term (i.e., next year or the year after) there should be no difference between contracted (purchased) RA and the quantity of RA to meet an LSE's obligation. <u>However, in later years (i.e., up to 2030), the LSE may not yet have RA contracts in place, so the LSE does not know what it will use to satisfy its RA obligation. In this case, the LSE can report what it expects to contract with (e.g., an unknown existing resource), or the LSE can choose to not speculate on what types of contracts it might sign in the future to meet its future RA obligations</u>.[12]

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[6] See PAO Opening Comments, at 3-4, PG&E Opening Comments, at 10, *Comments of Southern California Edison Company on Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability*, at 17 (December 20, 2018) ("SCE Opening Comments").

[7] SCE Opening Comments, at 10.

[8] PG&E Opening Comments, at 8.

[9] *Comments of California Community Choice Association on Integrated Resource Plans of Load Serving Entities*, at 2 (September 12, 2018) ("CalCCA Opening Comments on LSEs' IRPs").

[10] *Reply Comments of California Community Choice Association on Integrated Resource Plans of Load Serving Entities*, at 12 (September 26, 2018) ("CalCCA Reply Comments on LSEs' IRPs").

[11] CalCCA Opening Comments on LSEs' IRPs, at 3.

[12] Integrated Resource Plan (R.16-02-007) Filing Requirements Reference Guide (version July 20, 2018), at 5. Available at,

LSEs had flexibility in addressing future reliability needs and resources in their IRP filings. Simply because some CCAs may have chosen not to speculate on future contracts to meet future RA obligations (as permitted by the guidance provided on IRP filing requirements), does not mean that CCAs are not committed to meeting their ongoing RA requirements.

CalCCA also addressed SCE's erroneous assertions regarding the role of CCA IRP filings in its comments on the LSEs' IRP plans.[13] Although CCAs may have planning processes separate from their Commission mandated IRP filings, this does not in any way indicate that CCAs are not fully participating in the Commission's IRP process or that CCAs' IRP filings do not reflect their actual resource planning. Rather, those separate planning processes serve different functions than the Commission's IRP process, and may use more LSE-specific load forecasts and other inputs. For example, many CCAs plan to meet local goals in addition to meeting the RPS goals and GHG emissions benchmarks required in the Commission's IRP process. Nothing in the statutes mandating the IRP process prohibits this. The Commission has also expressly recognized that due consideration should be given to the "priorities and policies of local governing boards of CCAs whose local objectives may differ, at least in emphasis, for the statewide requirements …"[14]

Further, the Commission has acknowledged the need for flexibility in planning procurement. As stated in D.18-12-018:

> <u>Once *procurement* activities are undertaken, we expect that the LSEs will procure the most effective resources within the groups that meet their cost, reliability, and other needs such as impacts on disadvantaged communities, which may look different from what each LSE's plan proposes</u>.
>
> In sum, the purpose of the reference system portfolio is to point the general direction for planning purposes, for individual LSEs and policymakers, while being updated with better information at least every two years. Each LSE will be required to plan toward adherence to the reference system portfolio, with specific justification given when its plan deviates from the reference portfolio. <u>When it comes to actual procurement, we expect that LSEs will choose the most appropriate and effective resources offered to them that meet their customers'</u>

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http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/LSE_Filing_ReferenceGuide_20180720.pdf (emphasis added).

[13] CalCCA Reply Comments on LSEs' IRPs, at 12-14.

[14] D.18-02-018, at 30.

> <u>needs, when analyzing cost, reliability, and disadvantaged communities impacts, among other considerations</u>.[15]

LSEs' IRP filings provide a framework for future procurement; they do not dictate procurement of specific resources.

Finally, both PG&E and SCE raise the issue of enforcement of LSEs' IRPs.[16] As described in detail above, contrary to PG&E's and SCE's misstatements regarding CCAs' IRP filings, they are entirely consistent and compliant with statutory requirements and the Commission's direction in D.18-02-018. In addition, D.18-02-018 clearly addressed the Commission's authority over CCA IRP filings and found that while it is within the authority of the Commission to review and approve CCA plans, "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."[17]

CalCCA appreciates the opportunity to provide these comments and looks forward to working with the Commission and other stakeholders on the questions posed in the Joint Ruling.

Dated: January 14, 2019

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[15] *Id*. at 90-91 (emphasis added).

[16] PG&E Opening Comments, at 9-10; SCE Opening Comments, at 13-14.

[17] D. 18-02-018, at 26.

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)

COMMENTS OF THE JOINT CCAS ON PROPOSED PREFERRED SYSTEM PORTFOLIO AND TRANSMISSION PLANNING PROCESS RECOMMENDATIONS

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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)

COMMENTS OF THE JOINT CCAS
ON PROPOSED PREFERRED SYSTEM PORTFOLIO AND
TRANSMISSION PLANNING PROCESS RECOMMENDATIONS

In accordance with the January 11, 2019 *Administrative Law Judge's Ruling Seeking Comments On Proposed Preferred System Portfolio And Transmission Planning Process Recommendations* ("Ruling"), Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCP"), Silicon Valley Clean Energy ("SVCE"), the California Choice Energy Authority ("Cal Choice"), Peninsula Clean Energy ("PCE"), and Monterey Bay Clean Power ("MBCP") (the "Joint CCAs") respectfully submit the following comments on the Commission's Proposed System Portfolio and Transmission Planning Process ("TPP") recommendations.

I. RESPONSES TO QUESTIONS ON PRODUCTION COST MODELING RESULTS AND THE PREFERRED SYSTEM PORTFOLIO

Question 1:

> *Do you support the staff recommendation that the Commission adopt the hybrid conforming portfolio as the basis for the Preferred System Plan for the 2017-2018 IRP Cycle? Why or why not?*

Response to Question 1:

The Joint CCAs support the staff recommendation that the Commission adopt the Hybrid Conforming Portfolio ("HCP") as the basis for the Preferred System Plan ("PSP") for the 2017-2018 IRP cycle. Although the HCP's accuracy is hampered by a number of issues, addressing these issues at this late date in the IRP cycle would be inefficient and would risk overlap and inconsistency with the next IRP cycle. The Joint CCAs recognize that this first iteration of the

IRP process is, of necessity, a rough "trial run." As long as the flaws identified by CCA programs in these comments and elsewhere in this Rulemaking are adequately remedied in the 2019-2020 IRP cycle, the Joint CCAs believe that the HCP should be adopted as a reasonable first attempt at projecting the load-serving entities' ("LSE") combined portfolio in 2030.

The HCP supports a number of points that CCA programs have raised from the outset of the IRP Rulemaking. First, as CCA programs have repeatedly noted, CCAs are collectively and individually meeting the State's Greenhouse Gas ("GHG") reduction goals. According to RESOLVE, the HCP would reduce GHG emissions in the CAISO footprint to 34 MMT in 2030.[1] Individually, in many cases the conforming portfolios submitted by CCA programs would provide GHG reductions well in excess of those required to meet the programs' respective shares of required emissions reductions.

Second, the HCP demonstrates that CCA programs can be relied upon to drive new renewable resource development and the transition to a statewide renewable energy economy. Over 90% (well over 10,000 MW) of the HCP's proposed new procurement would come from CCA programs, while investor-owned utilities ("IOU") and energy service providers ("ESP") combined account for less than 10% (under 1000 MW) of proposed new procurement.[2] Tellingly, nearly 100% of CCA programs' new resource buildout proposed in the HCP is from renewable resources: over 6,500 MW of new solar (fixed and tracking); nearly 3,000 MW of new wind; and 1,000 MW of new 4-hour battery storage; and a small amount of geothermal.[3] The CCA programs do not propose any new fossil fuel generation or GHG-emitting biogas or biomass resources.[4]

1 *Administrative Law Judge's Ruling Seeking Comments On Proposed Preferred System Portfolio And Transmission Planning Process Recommendations* (January 11, 2019), Attachment 2 at Slide 88.
2 *Id.* at Slide 35.
3 *Id*. at Slide 34.
4 *Id*. at Slide 34.

Third, the HCP demonstrates that CCA programs can be relied upon to drive new resource development and achieve the States' GHG reduction goals *based on the local goals set by their governing boards*, and in *collaboration with the Commission*, without the need for the Commission to mandate renewable procurement. The HCP is composed, in significant part, of conforming portfolios voluntarily selected by CCA programs. These portfolios show that CCA programs will independently select renewable resources that drive GHG reductions.

Fourth, the HCP demonstrates that a portfolio with new procurement almost entirely driven by CCA programs is *reliable*. Commission Staff has established that the HCP, driven by over 10,000 MW of new CCA procurement, would achieve a high level of grid reliability, with a Loss Of Load Expectation ("LOLE") of .003, a mark that significantly exceeds the accepted reliability standard of 0.1 LOLE.[5]

While the Joint CCAs support the adoption of the HCP for the PSP in this initial IRP cycle, the HCP is hampered by a number of flaws that should be remedied in the 2019-2020 IRP process. First, the HCP is flawed because it is based only on *conforming portfolios*, ignoring the *preferred portfolios* submitted by a number of CCA programs. While some CCA programs submitted a single portfolio that served as both their conforming portfolio and their preferred portfolio, a number of CCA programs submitted separate preferred and conforming portfolios. These preferred portfolios are more accurate than the conforming portfolios, since they represent CCA programs' actual planned procurement, rather than procurement based on the "menu" of options provided by the Reference System Plan ("RSP"), and in some cases are based on more accurate inputs and assumptions than the RSP. For instance, Pico Rivera Innovative Municipal Energy ("PRIME") submitted a preferred portfolio that included a significantly higher, and more accurate, load forecast. Similarly, MCE submitted a preferred portfolio with more accurate load

5 *Id*. at 60, 67.

forecast that reflects the high penetration of Behind the Meter ("BTM") solar resources expected in MCE's service area.

The use of CCA programs' preferred portfolios rather than their conforming portfolios is more consistent with the CCA programs' procurement independence set forth in statute and recognized by the Commission in this proceeding.[6] In addition, the use of CCA programs' preferred portfolios is consistent with the ultimate goal of achieving the State's GHG reduction goals. In future iterations of the IRP process, the Joint CCAs anticipate that a number of CCAs may, consistent with their own internal planning processes and environmental goals, submit preferred portfolios that include *more renewable resources* and *greater GHG reductions* than their conforming portfolios. In the next IRP cycle, the Commission should produce and perform production cost modeling on at least two versions of the HCP – one version based on aggregated conforming portfolios, and a second based on a combination of IOU conforming portfolios (recognizing the Commission's regulatory mandate and extensive authority to direct IOU procurement) and CCA preferred portfolios.

Second, the HCP is flawed by the use of broad "top-down" statewide inputs and assumptions, even when more accurate LSE-specific information is available. While the Joint CCAs do not oppose the use of statewide inputs and assumptions to develop high-level statewide projections, the Commission should recognize the inherent limitations of such broad-brush projections, and where available rely on more granular inputs, assumptions, and load forecasts developed by each LSE. For instance, as SCP noted in its 2017-2018 IRP Compliance Filing, a number of the elements of the Commission's 2017-2018 IRP methodology led to inaccurate projections for SCP due to the Commission's use of statewide rather than LSE-specific

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6 *See,* Pub. Util. Code Section 366.2(a)(5) ("a community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute"); Section 454.52(b)(3); D.18-02-018 at 26, 29-30.

information.[7] For instance, the Commission used statewide California Energy Commission ("CEC") forecasts and assumptions to develop the 2017-2018 IRP's annual load forecast and to assign individual load forecasts to each LSE. Problematically, neither the IRP's statewide load forecast nor its LSE-specific forecast for SCP took into account SCP-specific assumptions regarding population growth, housing stock and fire rebuild efforts in Sonoma and Mendocino Counties, SCP opt-out rate, electric vehicle growth, other electrification, behind the meter solar, and expected energy efficiency.[8] The Commission's failure to incorporate these more accurate locally developed assumptions resulted in a significantly less accurate load forecast for SCP. In order to remedy this issue in future IRP cycles, the Commission should develop a process that starts with a statewide framework, but includes a mechanism for incorporating more accurate LSE-specific or area-specific information where such information is available.

Third, Commission Staff used different models to develop the RSP on the front end of the IRP process, and to assess the HCP on the back end. Specifically, staff used RESOLVE to develop the RSP, and a production cost model called SERVM to assess the consolidated LSE conforming portfolios. This led to some conflicting results, and a less accurate product than may otherwise have been achieved. While the Joint CCAs appreciate Staff's stated intent to work on ways to better align the two models, additional steps should also be taken. At a minimum, in future IRP cycles the Commission should use both RESOLVE and SERVM on the back end to evaluate the consolidated portfolios. In addition, it may be useful to use SERVM at the beginning of the IRP process to assess one or more potential conforming portfolios based on the RSP.

Fourth, this IRP did not account for reasonably anticipated load migration from IOUs to CCAs (and potentially ESPs). This issue is discussed in detail in the Joint CCAs' response to

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[7] Sonoma Clean Power, *2018 IRP Integrated Resource Plan Exhibit A - Narrative* (Submitted August 1, 2018) at 5.

[8] *Id*.

Question 17, below. Remedying this issue should be one of the Commission's top priorities in the next IRP cycle. The Joint CCAs stand ready to work with Commission staff and other stakeholders to develop a reasonable, broadly acceptable methodology for projecting new CCA formation and IOU load departure through the IRP planning horizon.

Fifth, the HCP was developed by consolidating individual LSE conforming portfolios that were developed using templates that do not fully or accurately reflect LSE procurement. Specifically, the IRP templates did not include a clear way to account for "portfolio product" contracts. In portfolio product contracts, the seller agrees to provide the buyer with a certain amount of power, with certain specified environmental attributes, from a large pool of resources. With such contracts, the purchaser knows the amount of power provided and the attributes of that power, but not the specific asset(s) that provided that power. These products are *extremely common* in the California electricity market, and are offered by a range of vendors, including Pacific Gas and Electric Company ("PG&E"). Because these contracts are not neatly tied to a specific asset, they are somewhat difficult to account for in the generation unit-specific IRP process. However, given the fact that these contracts guarantee certain attributes – attributes that purchasers pay a premium for – these contracts should not be treated as generic system power and should instead accurately reflect the guaranteed attributes. In addition, in the next IRP cycle the template should include combined solar and storage projects.

In light of these significant issues, the Joint CCAs urge the Commission to adopt the HCP with the understanding that, while this first "trial run" iteration of IRP provides useful insights regarding broad trends, this iteration of IRP has revealed a number of issues that must be remedied in the 2019-2020 IRP cycle.

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<u>Question 2</u>:

If you do not recommend the hybrid conforming portfolio form the basis of the PSP, what portfolio should the Commission utilize and why?

<u>Response to Question 2</u>:

The Joint CCAs recommend that the hybrid conforming portfolio be adopted as the basis of the PSP, subject to the above-listed issues being addressed in the next IRP cycle.

<u>Question 3</u>:

Are there reasons for the Commission to utilize a different portfolio (or portfolios) for transmission infrastructure planning (in the TPP) as distinct from the portfolio describing procurement actions of LSEs? Discuss.

<u>Response to Question 3</u>:

See the Joint CCAs' response to Questions 18 and 20, below.

<u>Question 4</u>:

Comment on whether or not the hybrid conforming portfolio is likely to result in a reliable system in 2030.

<u>Response to Question 4</u>:

The Joint CCAs agree with Commission Staff's conclusion that the HCP, a statewide portfolio driven in large part by over 10,000 MW of new renewable resource procurement by CCA programs, would be highly likely to result in a reliable system in 2030. The Joint CCAs believe that this conclusion will hold up in future iterations of the IRP cycle that more accurately account for local information and reflect CCA programs' planned procurement by aggregating CCA programs' preferred portfolios rather than their conforming portfolios.

Of particular interest to the Joint CCAs, the HCP includes a significant decrease in IOU procurement and increase in IOU reliance on system power through 2030. This increased reliance on system power does not reflect a procurement shortfall and should not raise any reliability concerns. The IOUs' plans to increase their reliance on system power going forward represents a strategy for hedging against reasonably expected load departure due to CCA formation. As discussed in the Joint CCAs' response to Question 17, below, this hedging strategy is entirely reasonable, and is consistent with the State's policy of protecting local choice, avoiding "on behalf of" procurement, and avoiding the complex and contentious problems created by stranded assets. As such, the IOUs' planned increasing reliance on system power should be viewed as proxy for expected load departure rather than an indication of any future reliability challenge. This reliance on system power (and any perceived shortfall created by this reliance) should disappear in future iterations of the IRP process as the Commission implements and refines a process that accounts for expected load departure, and CCA programs form or expand and procure on their new customers' behalf.

<u>Question 5</u>:

> *Are the adjustments made by staff to the geographic resource allocations proposed by LSEs to develop the hybrid conforming portfolio, as described in Section 2.1 above, warranted? What modifications would you make to these assumptions and why?*

<u>Response to Question 5:</u>

The Joint CCAs support the changes made by Staff to the geographic resource allocations proposed by LSEs. The geographic changes made by Staff involved only a small percentage of total expected procurement, and correct minor locational issues that were bound to come up. LSEs made their geographic resource choices without knowledge of the planned locations of other LSE's new resources. This fact, combined with the rough nature of the first iteration of the IRP process, means that LSEs' aggregated geographic resource allocations were almost certain to include some practical flaws. As CCA IRP plans move from planning toward execution, plans will self-correct to choose resources that are not transmission constrained. As a general matter, excess resources and resource potential should be available to meet expected demand. For instance, if Solano wind is oversubscribed, lots of excess wind resources are available in other areas.

LSEs are likely to differ significantly with regard to their priorities. Some LSEs may have little to no preference regarding the geographic location of a resource or resources, while others may have extremely strong interests in ensuring that their new procurement is located in a specific region or regions, without triggering unnecessary transmission upgrades. Similarly, while some parties may be fine with certain resources being re-designated as "energy only," this may raise significant issues for others. As such, the Joint CCAs appreciate that when aggregated portfolios showed that planned projects in an area exceeded transmission capacity or resource potential, the Energy Division contacted parties planning on building resources in those areas and gave willing parties the opportunity to either relocate or re-designate their projects. This practice should be continued in future iterations of the IRP process, and the Commission should continue to ensure that LSEs that view a project or project's location as "high priority" are accommodated to the greatest extent possible. This is especially true for CCA programs, which, as the Commission has recognized, retain procurement autonomy. If the Commission wants the IRP process to be truly accurate, the Commission should work to ensure that CCA IRP submissions reflect CCA programs' actual procurement plans (including locational preferences) without making unnecessary modifications to CCA portfolios.

Question 6:

> *Comment on the implications of the increased reliance on imports represented by the hybrid conforming portfolio.*

Response to Question 6:

As discussed in detail in response to Question 7, below, the Joint CCAs note that a large share of the imported power relied on by CCA programs' is imported hydroelectric power from the Pacific Northwest ("PNW"). As discussed below, the Joint CCAs agree with the Commission's conclusion that this planned reliance does not raise any legitimate resource availability, reliability, or transmission capacity concerns.

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Question 7:

> *Comment on the hydroelectric feasibility analysis conducted by staff. Should the Commission require additional or different approaches to reliance on hydroelectric resources? What are your specific recommendations?*

Response to Question 7:

The CCA programs strongly support the staff conclusions regarding the reasonableness of LSEs' planned procurement of PNW Hydro. This analysis is consistent with previous comments submitted by CalCCA in this proceeding:

> There is little doubt that the future procurement plans [of the CCAs] are feasible. The RESOLVE model documents 7,844 MW of large hydro capacity within CAISO with another 4,766 MW within other regions of California (e.g., Imperial Irrigation District and Los Angeles Department of Water and Power), and 38,370 MW within the Northwest and Southwest regions. As already indicated, approximately 4,000 MW of Large Hydro/ACS is already under contract in 2018 and more than adequate capacity should be available in future years based on expected re-contracting and the large amount of capacity in the RESOLVE model. Even assuming that the entire 1,000 MW of additional hydro resources planned by CCAs are expected from out-of-state Large Hydro, adequate transmission capacity appears available to meet those needs. More specifically, there is 4,800 MW and 3,100 MW of transmission capacity at the California Oregon Intertie and Pacific DC Intertie, respectively, which can adequately meet the planned CCA demands.[9]

These conclusions should be explicitly incorporated in the 2019-2020 IRP. In addition, the emissions factor for unspecified PNW imports should be modified to reflect their high average hydro content and relatively low GHG emissions compared to generic system power.

Question 8:

> *Comment on any actions the Commission should take to mitigate drought risk, especially for in-state hydroelectric resources.*

Response to Question 8:

To address and mitigate drought risk, in the next IRP cycle Commission Staff should, at a minimum, include low in-state hydroelectric year scenarios in the modeling.

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[9] *Comments of California Community Choice Association on Integrated Resource Plans of Load Serving Entities* (September 12, 2018) at 3.

<u>Question 9</u>:

> *Comment on the potential for WECC-wide resource shuffling and how the Commission should address it.*

<u>Response to Question 9:</u>

As a threshold matter, it is important that the Commission keep the question of resource shuffling in perspective. Some parties have been especially dogged about raising concerns regarding resource shuffling, voicing these concerns so often that it would be easy to mistakenly assume that resource shuffling has been established to be an actual problem. This, however, is simply not the case. The CCA Parties are unaware of any actual evidence on the record in this proceeding – or any other proceeding – that provides a concrete example of resource shuffling actually occurring. Prior to attempting to "fix" resource shuffling, stakeholders must first identify when and where it is happening. Absent this, any attempt by the Commission to address resource shuffling would be a solution in search of a problem.

Even if one could reasonably *speculate* that some renewable power imported into California could possibly be locally replaced with additional fossil generation, such conjecture would fall far short of concrete evidence of an actual problem, and would provide no insight regarding the (likely small) scope and impact of the problem if it actually does exist.

Further, there are strong reasons to believe that concerns regarding resource shuffling are either unfounded or, at the minimum, highly exaggerated. First, a significant share of the imported resources that CCA programs rely on are imports of PNW hydroelectric power. PNW hydroelectric providers have submitted comments explaining that their exports to California are primarily *excess* hydroelectric capacity.[10] In other words, the exports to California are not "shuffled" with any generation to meet local need. Further, any power exported from the PNW is unlikely subject to be "shuffled" with GHG-emitting fossil generation due to the PNW area's

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[10] *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.

very high GHG-free resource portfolio. For instance, today only 11% of Washington State's unspecified fuel mix is from natural gas,[11] while by 2022 roughly *90%* of the energy generated in Washington State will be from GHG-free resources.[12]

Second, concerns regarding resource shuffling ignore the impact of environmental laws, policies, and goals adopted by other states, localities, and individual utilities. The California Air Resources Board ("CARB") specifically prohibits resource shuffling under its cap-and-trade program. The hydroelectric providers in the PNW are governed by the Northwest Power Act, which prohibits electricity generation providers from selling energy to out-of-state LSEs before serving their load in the PNW. In addition, these providers are subject to a number of state laws that reduce the likelihood of resource shuffling. For instance:

> Washington State's renewable portfolio standard will increase to 15% in 2020. Washington State also has GHG emission reduction goals to reduce GHG emissions to 1990 levels by 2020, and 25% below 1990 levels by 2035. Washington State is on track to meet or exceed these interim targets with the measures outlined above and is considering deeper de-carbonization goals consistent with the State of California.[13]

These policies are not limited to Washington State. Oregon has a 50% renewables portfolio standard ("RPS") for IOUs and a multi-sector Cap-and-Trade Program.[14] In light of these considerations, it is highly unlikely that hydroelectric providers have the ability to engage in resource shuffling, given the penalties associated with violating the CARB's regulations, the Northwest Power Act, and State RPS, cap-and-trade, and GHG-reduction requirements.

Third, concerns regarding resource shuffling ignore the economics of renewable power. Renewable power costs are dropping significantly, in some cases renewable power is actually more affordable than power from fossil plants.

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11 *Id*. at 4 (FN. 3).
12 *Id*. at 5.
13 *Id*.
14 *Id*.

Fourth, concerns regarding resource shuffling ignore the impact of increasing public awareness of climate change and growing customer demand for renewable energy outside of California (particularly in the PNW area).

All of these factors make it much more likely that hydroelectric power imported to California is either not needed to meet local need, or is likely to be "shuffled" *with other renewable power*.

Ultimately, there are limitations on what California's IRP process can measure and achieve. Concerns regarding increased GHG emissions in other states should be addressed by California in cooperation with the appropriate agencies of the state in question.

Question 10:

Comment on additional hydroelectric analysis that should be conducted in the future.

Response to Question 10:

The Joint CCAs agree with the Commission's conclusions regarding PNW hydro and do not believe that any further analysis in this IRP cycle is warranted. Staff's conclusions should be adopted 2019-2020 IRP cycle and used in developing the 2019-2020 RSP. In addition, as MCE and SCP argued in recent comments, in future iterations of the IRP process the Commission should use RESOLVE to project future PNW hydro availability.[15]

Question 11:

Comment on the calibrated LOLE study conducted for 2030. What are the implications or policy actions that should result, if any?

Response to Question 11:

The Joint CCAs believe that the calibrated LOLE study's conclusions are reasonable. The calibrated LOLE study's results do not require any action by the Commission in the 2017-2018 IRP cycle.

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15 *Comments of Marin Clean Energy and Sonoma Clean Power Authority on Inputs and Assumptions for Development of the 2019-2020 Reference System Plan* (January 4, 2019) at 5.

Question 12:

> *Comment on the differences between the hybrid conforming portfolio and the portfolio associated with the RSP calibrated to the 2017 IEPR assumptions. What are the implications of these differences and how should they be addressed?*

Response to Question 12:

The CCA Parties view the differences between the HCP and the RSP as natural (and inevitable) differences between a centrally planned and projected portfolio and a portfolio that more accurately reflects LSEs' actual preferences.

If anything, the CCA parties are surprised and encouraged by how closely aligned the HCP and RSP turned out to be. The Commission should view the differences between the RSP and HCP as *improvements* to the RSP. The RSP is the portfolio selected as a result of statewide modeling. The HCP takes the broad perspective provided by the RSP and adds, to a limited extent, resource choices informed by individual LSEs' far more intimate and detailed knowledge of their operations, plans, and the specific needs of the communities and customers they serve. This is particularly true of CCA programs, which, by statute, are formed for the purpose of allowing local communities to choose their own energy/resource mix. Further improvements along these lines can be achieved in future IRP cycles using an HCP consisting of IOU conforming portfolios and CCA programs' preferred portfolios.

Question 13:

> *Comment on the criteria pollutant emissions results for the hybrid conforming portfolio. Is there further analysis that staff should conduct on criteria pollutant emissions for these high-level portfolio purposes? Explain.*

Response to Question 13:

The Joint CCAs do not have a response to Question 13 at this time, but reserve the right to comment on this matter going forward.

Question 14:

> *Comment on the GHG emissions results from the hybrid conforming portfolio analysis in SERVM. What are the implications and what should the Commission change as a result? (presuming that a new RSP will be analyzed in 2019-2020 already).*

Response to Question 14:

The Commission should not take any action in the 2017-2018 IRP cycle based on the GHG emissions results from SERVM. This iteration of the IRP process has served its function and revealed problems to be addressed in future IRP iterations. The difference between SERVM and RESOLVE's GHG emissions projections for the RSP and the differences between SERVM's projections for the RSP and HCP are among these problems.

For the 2019-2020 IRP cycle, the Commission should make a range of corrections to the IRP process, including those discussed elsewhere in these comments. Among these changes, the Commission should take steps to further align SERVM and RESOLVE, and should use RESOLVE as the primary tool for assessing the HCP's emissions.

However, at the end of the day, SERVM and RESOLVE are different models that are designed to perform different functions. It is unlikely that the Commission will ever achieve perfect alignment of these different models' conclusions. As such, the Commission should use the models in a manner consistent with their primary intentions. RESOLVE should be the primary model used to develop the RSP and assess GHG emissions. SERVM should be a secondary (support) model used to assess costs and reliability of the aggregated portfolio. SERVM's GHG emissions results may provide some insights or a helpful "second opinion" but should not be relied upon as the primary measure of an aggregated portfolio's emissions.

Question 15:

> *Comment on the curtailment results of analyzing the hybrid conforming portfolio.*

Response to Question 15:

The Joint CCAs do not have a response to Question 15 at this time, but reserve the right to comment on this matter going forward.

Question 16:

> *Should the Commission place additional or tighter requirements on LSEs filing IRPs in the next IRP cycle? Suggest specific requirements and explain your rationale.*

Response to Question 16:

The CCA Programs only respond to this question as it applies to CCA IRP submissions. "Additional" or "tighter" requirements on CCAs submitting IRPs are neither needed nor appropriate. As discussed in the Joint CCAs' response to Question 1, above, the HCP demonstrates that CCA Programs, working with the Commission, but ultimately making their own procurement decisions, can be counted on to achieve the State's GHG reduction, renewable energy, and reliability goals. The Joint CCAs recognize the incredible value that the IRP process provides CCA programs. Through IRP, the Commission has given CCA programs a set of tools and insights that will allow them to better plan future resource procurement and identify the resources that resources that most cost-effectively achieve state requirements, and, in many cases, their own more ambitious internal environmental goals. Empowered by this process, and working in coordination with the Commission, CCA programs can be counted on to exercise their independent procurement authority in a manner consistent with the state's goals without further Commission intervention.

In addition to being unnecessary, any "additional" or "tighter" requirements on CCA programs would be inappropriate. The Commission's role in certifying CCA IRPs is defined by statute (and further elaborated in D.18-02-018). Both Public Utilities Code Section 454.52 and this Decision include language that recognizes and preserves CCA programs' planning and procurement independence. Any "additional" or "tighter" requirements for CCA programs would almost certainly overstep this role and impinge on CCA programs' procurement independence.

Question 17:

Comment on any other aspects of the hybrid conforming portfolio analysis.

Response to Question 17:

The Ruling and Attachments note that the IOUs plan very little new procurement, and generally plan to increase their reliance on system power as their baseline resources retire or contracts expire.[16] The Commission notes that this is likely a strategy to avoid stranded assets in the event of future departing load. This hedging strategy is a *good thing*, and in future IRP iterations the Commission should develop a methodology for projecting CCA formation and IOU load departure, and actively encourage, if not require, that IOUs hedge against projected load departure.

Hedging against reasonably projected load departure avoids stranded assets with associated stranded costs that the IOUs would likely attempt to allocate to departing customers through cumbersome, inefficient, and highly contentious mechanisms like the Power Charge Indifference Adjustment ("PCIA") or some successor charge. In addition, hedging against reasonably projected load departure is consistent with CCA procurement independence and local choice, as it represents a reasonable step to avoid "on behalf of" procurement.

Load departure should be formally accounted for in IRP. In the 2019-2020 IRP cycle, one of the Commission's top priorities should be to work cooperatively with CCA programs, the IOUs and other interested parties to develop a formal methodology for projecting IOU load departure due to CCA formation. This methodology should allow the development of multiple scenarios with different levels of load departure for each IOU. In addition, the methodology, and IOU hedging strategies, should take the timing of expected load departure and lead-up times necessary for the development of various resource types into account. At an absolute minimum, the IRP should account for *announced* CCA formation. For instance, the City of San Diego has announced its intent to form a CCA program. In light of this announcement, the Commission should neither require nor allow San Diego Gas & Electric Company ("SDG&E") to plan for procurement on behalf of customers that will be served by the City's CCA program well before 2030.

II. RESPONSES TO QUESTIONS ON TPP PORTFOLIOS

Question 18:

> *Should the hybrid conforming portfolio be analyzed as the reliability base case in the 2019-20 TPP? Why or why not? What changes would you recommend? Comment on any other aspects of the hybrid conforming portfolio analysis.*

Response to Question 18:

The Joint CCAs support the use of the HCP as the reliability base case in the 2019-2020 TPP. However, given the rough nature of this first IRP cycle and the significant issues that need to be remedied in the next IRP cycle, the Joint CCAs recommend that no significant transmission modifications or investments be made based on the HCP. CAISO should defer any significant decisions until the 2019-2020 IRP portfolio is finalized.

Question 19:

> *Should the hybrid conforming portfolio be analyzed as the policy-driven base case in the TPP? Why or why not? What changes would you recommend?*

Response to Question 19:

The Joint CCAs do not have a response to Question 19 at this time, but reserve the right to comment on this matter going forward.

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[16] *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Portfolio and Transmission Planning Process Recommendations* (January 11, 2019), Attachment 2 at Slides 23, 35.

Question 20:

> *What are the potential implications if the CAISO analyzes the hybrid conforming portfolio and takes transmission investments to the CAISO Governing Board, if the resource procurement by LSEs between now and 2030 turns out to be significantly different than the hybrid conforming portfolio suggests? If this is a concern, suggest potential remedies or other analysis or actions that could be taken.*

Response to Question 20:

CAISO should not take any transmission investments based on the HCP to the CAISO governing board. The 2017-2018 IRP process is a practice run, and the HCP should be treated as a rough draft – informative, but not authoritative. Future iterations of the IRP are likely to be significantly more accurate, and CAISO has more than adequate time between now and 2030 for even long lead-time transmission projects.

Question 21:

> *Do you support the staff recommendation to transmit two policy-driven sensitivity scenarios (Case B and Case C) to the CAISO for further analysis as policy driven sensitivity scenarios? Why or why not? What changes would you make?*

Response to Question 21:

The Joint CCAs do not have a response to Question 21 at this time, but reserve the right to comment on this matter going forward.

Question 22:

> *Do you agree with the Commission staff assumptions used to develop policy-driven sensitivities, with respect to electric vehicle load, GHG emissions constraints in 2030, etc.? Explain in detail.*

Response to Question 22:

The Joint CCAs do not have a response to Question 22 at this time, but reserve the right to comment on this matter going forward.

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<u>Question 23</u>:

Comment on any other aspects of the Commission's recommendations to the CAISO for TPP purposes.

<u>Response to Question 23:</u>

The Joint CCAs do not have a response to Question 23 at this time, but reserve the right to comment on this matter going forward.

III. RESPONSES TO QUESTIONS ON COMMISSSION POLICY ACTIONS

<u>Question 24</u>:

What further policy or procurement actions should the Commission take as a result of the analysis presented in this ruling? Explain your recommendations in detail.

<u>Response to Question 24:</u>

The Commission should explicitly find that each CCA program's IRP adequately contributes to a statewide portfolio that achieves the goals of Senate Bill 350. As such, the Commission should certify each CCA program's IRP submission.

In addition, the Commission should find that the HCP as a whole, and in particular new procurement planned by CCA programs, satisfies the State's renewables integration resource need and each CCA programs' individual share of that need.

<u>Question 25</u>:

Is an increase in the RPS compliance requirement, beyond 60 percent RPS in 2030, warranted? Why or why not?

<u>Response to Question 25:</u>

An increase in the RPS compliance requirement beyond 60 percent RPS in 2030 is not warranted at this late point in the 2017-2018 IRP cycle. This question should be addressed in the 2019-2020 IRP cycle.

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<u>Question 26</u>:

Acknowledging that near- and mid-term reliability issues have been addressed in comments in response to a separate ruling in this proceeding, should the Commission order any resource procurement in the context of the IRP proceeding at this time? How much? Explain your rationale.

<u>Response to Question 26:</u>

The Commission should not order any procurement in the 2017-2018 IRP cycle.

IV. CONCLUSION

The Joint CCAs thank the Commission for its consideration of these comments.

Dated: January 31, 2019

Respectfully submitted,

<u>/s/ David Peffer</u>

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NOTE: It is Energy Division's preference to have document components combined into one PDF document with the top sheets being the cover sheet, the next an executive's letter (as applicable), and the compliance data as the third element.

A. Document Name

Today's Date: **1/7/2019**

1. Utility Name: **Marin Clean Energy**
2. Document Submission Frequency (Annual, Semi-Annual, YTD, Quarterly, Monthly, Weekly, Ad-hoc, Once, Other Event): **Monthly**
3. Report Name: **Monthly Report of Marin Clean Energy on Its Low Income Families and Tenants Pilot Program for November 2018**
4. Reporting Interval (for this submission, e.g. 2015 Q1 – that data date): **Report Month - November 2018**
5. Document File Name (format as 1+2 + 3 + 4): **Marin Clean Energy Monthly LIFT Report November 2018 20190107**
6. Append the confidential and/or cover sheet notation, as appropriate. Click here to enter text.

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SCE Annual Procurement Report 2015	*West Coast Gas Company Monthly Gas Report 201602* CONF
SDG&E Quarterly DR Forecast 2015Q1	*West Coast Gas Company Daily Gas Report 201602*30 COV
West Coast Gas Company Monthly Gas Report 201602	*West Coast Gas Company Monthly Gas Report 201602* COV CONF
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B. Documents Related to a Proceeding

All submittals should reference both a proceeding and a decision, if applicable. If not applicable, leave blank and fill out Section C.

1. Proceeding Number (starts with R, I, C, A, or P plus 7 numbers): **A.14-11-007**
2. Decision Number (starts with D plus 7 numbers): **D.16-11-022**
3. Ordering Paragraph (OP) Number from the decision: **D.16-11-022, Ordering Paragraph 147, and D.16-11-022 at p. 390**

C. Documents Submitted as Requested by Other Requirements

If the document submitted is in compliance with something other than a proceeding, (e.g. Resolution, Ruling, Staff Letter, Public Utilities Code, or sender's own motion), please explain: Click here to enter text.

D. Document Summary

Provide a Document Summary that explains why this report is being filed with the Energy Division. This information is often contained in the cover letter, introduction, or executive summary.

This report is being filed pursuant to D.16-11-022, which directed Marin Clean Energy (MCE) to submit monthly reports on the Low Income Families and Tenants (LIFT) pilot's progress. This monthly report presents LIFT's progress, results, and expenditures from LIFT's launch on October 31, 2017 through November 30, 2018.

Pursuant to a granted request for extension from Energy Division staff, this monthly report is being filed and served four business days after the first of the month. Energy Division staff granted this one-time extension request on December 12, 2018, which permitted MCE to file this monthly report on or before January 7, 2019. Pursuant to Energy Division staff's direction, on December 17, 2018, MCE also advised the service list for Application 14-11-007 *et al*. of this extension via email.

E. Sender Contact Information

1. Sender Name: **Nathaniel Malcolm, MCE Policy Counsel**
2. Sender Organization: **Marin Clean Energy**
3. Sender Phone: **415-464-6048**
4. Sender Email: **nmalcolm@mcecleanenergy.org**

F. Confidentiality

1. Is this document confidential? ☒No ☐Yes

   a. If Yes, provide an explanation of why confidentiality is claimed and identify the expiration of the confidentiality designation (e.g. Confidential until December 31, 2020), and a signed declaration of confidentiality. Click here to enter text.

G. CPUC Routing

Energy Division Central Files Document Coversheet

Energy Division's Director, Ed Randolph, requests that you <u>not</u> copy him on filings sent to Energy Division Central Files. Identify below any Commission staff that were copied on the submittal of this document.

1. Names of Commission staff that sender copied on the submittal of this Document: **Sarah Lerhaupt (**Sarah.Lerhaupt@cpuc.ca.gov**); Syreeta Gibbs (syreeta.gibbs@cpuc.ca.gov)**

ver.12/05/2017

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

MONTHLY REPORT OF MARIN CLEAN ENERGY ON ITS LOW INCOME FAMILIES AND TENANTS PILOT PROGRAM FOR NOVEMBER 2018

Nathaniel Malcolm
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Attorney for:
MARIN CLEAN ENERGY

January 7, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) 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

MONTHLY REPORT OF MARIN CLEAN ENERGY ON ITS LOW INCOME FAMILIES AND TENANTS PILOT PROGRAM FOR NOVEMBER 2018

In accordance with Decision 16-11-022, Marin Clean Energy ("MCE") hereby submits its *Monthly Report of Marin Clean Energy on Its Low Income Families and Tenants Pilot Program for November 2018* ("November 2018 Monthly Report"). This November 2018 Monthly Report presents the Low Income Families and Tenants ("LIFT") pilot's progress, results, and expenditures from the launch on October 31, 2017 through November 30, 2018.

Pursuant to a granted request for extension from Energy Division staff, the November 2018 Monthly Report is being filed and served four business days after the first of the month. Energy Division staff granted this one-time extension request on December 12, 2018, which permitted MCE to file this monthly report on or before January 7, 2019.

Pursuant to Energy Division staff's direction, MCE also advised the service list for Application 14-11-007 *et al*. of this extension via email on December 17, 2018.

Respectfully submitted,

/s/ *Nathaniel Malcolm*

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Dated: January 7, 2019

MONTHLY REPORT OF MARIN CLEAN ENERGY ON ITS LOW INCOME FAMILIES AND TENANTS PILOT PROGRAM FOR NOVEMBER 2018

Marin Clean Energy

Monthly Report of Marin Clean Energy on Its Low Income Families and Tenants (LIFT) Pilot Program for November 2018

Pilot Program Launch Date: Oct. 31, 2017

Report Month: November 2018

LIFT Monthly Report Number: 13

Table 1. Budget and Expenditures[1]	Pilot Program	EM&V	Total
2 Year Pilot Approved Program Budget	$ 3,360,000	$ 140,000	$ 3,500,000
Expenditures (Report Month)	$ 25,291	$ -	$ 25,291
Expenditures (Pilot-Launch-to-Date)	$ 308,169	$ 58,818	$ 366,988
Committed Rebates (Non-Heat Pump Pilot)	$ 32,930		$ 32,930
Committed Rebates (Heat Pump Pilot)	$ 423,320		$ 423,320
Available Programs Budget as of Report Quarter	$ 2,595,581	$ 81,182	$ 2,676,762

[1] Monthly report expenditures are estimates based on information available at the time of reporting. Pilot-launch-to-date expenditures are trued-up, as necessary, in future monthly and quarterly reports.

Table 2. Pilot Savings[2]	Actual Savings- Report Month	Actual Savings - Pilot Launch through Report Month	Projected Savings- Report month	Projected Savings - Pilot Launch through Report Month
Annual Energy Savings (kWh)	0	0	-	2,466
Annual Demand Savings (kW)	0	0	-	0.00826
Annual Gas Savings (therms)	0	0	340	914

[2] Pilot savings above, do not include savings associated with heat pump pilot measures. Reported therms savings are associated with non-heat pump measures such as showerheads, aerators, etc. Savings associated with heat pump pilot measures will be reported at completion of the pilot.

Table 3. Pilot Measures [3]	Quantity
LED Bulbs	0
LED Fixtures	0
Energy Star Refrigerators	0
Duct Sealing	0
Attic Insulation	0
Showerheads	0
Faucet Aerators	0

[3] These measures will be installed, as appropriate, before offering additional measures using LIFT funds.

Table 4. Households Treated	Units Treated Launch to Date			Properties Treated Launch to Date		
County	Rural[4]	Urban	Total	Rural	Urban	Total
Marin	0	0	**0**	0	0	**0**
Contra Costa	0	0	**0**	0	0	**0**
Benicia	0	0	**0**	0	0	**0**
Napa	0	0	**0**	0	0	**0**
Total	**0**	**0**	**0**	**0**	**0**	**0**

[4] For low income-related and Energy Efficiency reporting and analysis, the Goldsmith definition is applied.

Table 5. Metrics Tracking[5]	Report Month	Pilot Launch through Report Month[8]
Number of participating units[6]	405	920
Number of units expected to install heat pumps	1	97
Number of participating properties	3	18
Number of properties expected to install heat pumps	0	2
Number of heat pumps in rebate reservation	1	97
Number of heat pumps installed	0	0
% of units meeting one or more of the Hidden Community criteria[7]	100%	100%

[5] Some or all of these units may be receiving additional rebates through LIFT and/or MCE's Multifamily Energy Savings Program.

[6] A participating unit is generally defined as a unit that has passed the income-qualification process, paid a refundable Good Faith Deposit, and received a site assessment from the program's technical assistance provider. However, because MCE applies the 80% ESA-eligible tenant multifamily household eligibility rule (80% Rule), if at least 80% of units at a given property qualify as income-eligible, MCE treats all units at that property. Thus, for properties that satisfy the 80% Rule, the total number of participating units equals the total number of units at the property (i.e. both income-eligible units and units that do not meet the income eligiblity requirements, but are located at a property where 80% or more of the units are income-qualified).

[7] Hidden Community Criteria is defined as meeting one or more of the following:

a. Residents receive program information in a language other than English (will track languages)

b. Residents are engaged by community based organizations (CBOs) who indicate they had not previously participated in energy efficiency programs due to concerns around sharing personal information

c. Located outside of Cal Enviro Screen 2.0 designated disadvantaged communities

d. Are occupied by extended or multiple families

[8] This number is trued-up, as necessary, in future monthly and quarterly reports to include any units that did not initially meet income-qualification requirements at a treated property, but that satisfied income-qualification requirements at a later date.

MCE 2019 ABAL Workshop – January 11, 2019

Background

Energy Division approved MCE's 2019 ABAL on November 27, 2018. As required by Decision 18-05-041, Program Administrators were directed to host a workshop within 45 days of its ABAL approval and subsequently develop and serve a report to R.13-11-005 summarizing the workshop within 15 days.

MCE hosted its 2019 ABAL Workshop at its Concord office, 2300 Clayton Rd 11th Floor Suite 150, on January 11, 2019. Fourteen individuals participated in-person and twenty-two more via GoTo Webinar. A full list is provided in Appendix A: In-Person and Webinar Participation.

The ABAL workshop was opened by Alice Stover who provided a brief overview of MCE's business model and mission. MCE's 2019 portfolio of programs were discussed by Joey Lande (non-residential) and Grace Peralta (residential). Qua Vallery addressed how MCE intends to achieve a portfolio TRC that meets or exceed 1.0 on an evaluated basis and transition to a TRC forecast of 1.25 by the program year 2023.

Following the presentation, the workshop turned into an open discussion to answer questions and gather feedback from stakeholders. Key clarifying questions and responses are listed in this document. Questions are in bold whereas responses are noted in italics.

The presentation can be downloaded here: https://www.mcecleanenergy.org/wp-content/uploads/2019/01/MCE-2019ABAL-FinalPresentation-2019_0110.pdf

2019 Portfolio Overview

Existing Residential Programs

Multifamily Comprehensive Program

This program provides complimentary walk-through assessments and technical assistance to identify energy and water savings opportunities at multifamily properties. The program provides cash rebates, assists with contractor bid solicitation as well as educate and train operations and maintenance staff to support the implementation of energy upgrades.

Single Family Seasonal Savings Program

This program offers customers the opportunity to make their cooling and heating schedules more efficient through a series of small adjustments to scheduled temperatures by a software algorithm. Customers are offered the program on their thermostat and/or through a phone app and must opt-in to participate.

New Residential Programs

Multifamily and Single-Family Direct Install Programs

These programs will provide low to no-cost energy and water savings upgrades, health and safety measures, and access to other resources and non-energy services for single-family homeowners and renters. This will include conservation education.

Multifamily and Single-Family Single Measure Programs

These programs will provide homeowners with the opportunity to receive one-off rebates for measures including lighting, HVAC, insulation, and efficient appliances. There will be higher rebates for measures that offer benefits across multiple resources such as water-energy.

Single Family Comprehensive

This program will offer a variety of strategies including, but not limited to, behavioral interventions, zero net energy, new construction, and comprehensive retrofits.

Existing Non-Residential Programs

Commercial Program

The program provides support to all commercial customers in MCE's service area. Its primary objectives are to facilitate the uptake of high-quality energy efficiency projects, and improve the technical capability, pricing and program experience of both customers and the local contractor community. The program aims to achieve these objectives through a customer and contractor-friendly project assessment platform, competitive bidding, contractor training resources and ongoing coordination with PG&E programs, which also serves commercial customers. The program is undergoing an expanded scope, alongside new customer and contractor engagement strategies.

New Non-Residential Programs

Agricultural and Industrial

These programs will provide technical project development resources, procurement support and a mix of deemed and calculated incentives for agricultural and industrial customers.

Strategies for Meeting and/or Exceeding a 1.0 TRC on an Evaluated Basis

- **Focus on most cost-effective measures**
  Prior to 2019, MCE offered energy efficiency programs with an emphasis on customer experience and comprehensive projects. In order to meet cost-effectiveness standards, MCE is modifying this approach by being strategic with program participation and reducing the number of non-cost-effective measures offered to its customers.

- **Deploy measure cost savings strategies within existing programs**
  In past program years, MCE has not employed any program strategies aimed at controlling or capping total measure costs. Considering measure cost is a significant driver of cost-effectiveness, MCE is considering equipment cost caps and markup maximums for specific measures and contracts.

  Expanded portfolio
  Prior to 2019, MCE portfolio was limited to residential and small commercial. With the expansion of MCE's portfolio, MCE can target a larger population of projects, including large commercial, industrial and agriculture. The expanded service area also provides a greater variety of customers to target including a larger population in a hotter climate zone.

- **Comprehensive sector-related programs**

MCE will layer offerings and funding streams to facilitate program participating and reduce overall project costs.

- **Use of performance-based implementation contracts**
  MCE is moving away from time and materials contracts to performance-based implementation contracts. This allows MCE to set rates that it can afford to pay for savings while hitting cost-effective targets.

Transitioning to a TRC of 1.25 and New Program Ideas

- **Expanding to a comprehensive portfolio**
  Prior to 2019, MCE's portfolio was limited to residential and small commercial. With MCE's broader portfolio, MCE can target savings in different customer segments such as agricultural, industrial and large commercial which are historically more cost-effective.

- **Adaptive management**
  MCE will take an adaptive management approach to continuously evaluate its programs by using advanced metering infrastructure (AMI) data, customer feedback, among other sources to measure the effectiveness of intervention strategies. This feedback loop will enable MCE to make improvements throughout the program cycle.

- **Targeted outreach**
  MCE will reach its customers through a sophisticated CRM system which will identify opportunities with customers. Additionally, MCE will target hard-to-reach customers and disadvantaged communities, which will result in less program free ridership.

- **Adopt new technologies**
  MCE plans to adopt new technologies as they come to the market to reduce the market gap.

- **Implement a competitive bidding process**
  MCE will utilize a robust, formal and competitive solicitation process.

- **Engage community partners to create access to MCE programs for all communities**
  Local partnerships provide a foundation for deepening market penetration, including helping to serve hard-to-reach residents, low-to-moderate income households, and non-English speaking households, who often miss out on services due to language barriers. Although MCE is moving towards a single point of contact (SPOC) model, MCE is still invested in partnerships to provide customers with integrated solutions by minimizing customer confusion and maximizing program uptake.

- **Expanded workforce development**
  MCE understands that a growing network of trained local contractors can help achieve deeper market penetration by identifying trigger events that could bring customers to energy efficiency programs. MCE plans to continue to partner with local workforce development organizations to provide articulated career pathways with on and off ramps based on the participant.

- **Zero net energy (ZNE)**
  CPUC and CEC have reinforced a commitment to increased development of ZNE buildings in California. MCE plans to provide design assistance to local architects and contractors to assist in the integration of ZNE strategies at the onset of a project.

- **New Construction**
  MCE will target new construction buildings and sites with major renovations that trigger building permit and code compliance. MCE will offer education, performance-based incentives and financing options to defray upfront costs. Additionally, customers who achieve ZNE will receive a bonus incentive.

- **Data Analytics and behavior approaches/program**
  MCE plans to offer a complimentary-web based tool that focuses on customer usage data and integrating demand response, renewable energy, electric vehicle, and storage offerings while also offering education on energy efficiency.

- **Normalized metered energy consumption (NMEC)**
  MCE plans to explore normalized metered energy consumption as a component of its portfolio to increase the accuracy of projected energy savings and validate savings post-installation. This would also provide customers with greater certainty in savings and more accurate results on an evaluated basis.

- **Single point of contact (SPOC) model buildout**
  To enable the cost-effective execution of MCE's portfolio, MCE will assume the role of the Single Point of Contact (SPOC) for its service area to eliminate customer confusion around multiple program offerings and to avoid overlapping customer outreach activities between MCE, statewide and local government programs.

Clarifying Questions and Comments on MCE's Presentation

Question: Has MCE used the adaptive management strategy before?

MCE has used an adaptive management strategy in the past to make changes to programs mid-cycle based on reported energy savings or costs, but we will be building in additional data streams, such as AMI data or customer feedback to enhance our ability to make ongoing improvements to programs.

Question: Are there lessons learned and are there other groups still figuring things out with AMI? Is MCE working with the same implementer or separate implementer to look at results of AMI findings?

MCE is working with Open EE to evaluate our ability to apply AMI data analysis to our programs. We are working through issues of data access. MCE has done a complete AMI analysis on PACE projects in Marin, but we are still working on how to build an EE program around AMI data and how it looks customer facing. MCE will be working with a separate partner organization who is not the program implementer to analyze savings of a particular program using AMI findings.

Question: How does MCE define community partners?

MCE views community partners broadly. A community partner is an organization with boots on the ground and an intimate understanding of the constraints a community or demographic faces and the effective strategies or interventions to address them.

Question: Is MCE going to have a performance-based program for commercial now or down the road in 2020?

MCE will be targeting a commercial performance-based and/or NMEC down the road. Residential is MCE's first target for NMEC and Pay-for-Performance (P4P). MCE will be working with BayREN and PG&E to go through lessons learned.

Question: Resolution E-4952 DEER updates - How will the DEER resolution impact your programs? Will they still be cost-effective (peak hour time changes, etc.)?

MCE is undergoing evaluation of these impacts on our programs and is looking at strategies in its original business plan and seeing if they still make sense with this DEER update. For example, MCE's Single-Family Single Measure might be a program that doesn't make sense anymore depending on how the DEER update impacts those measures.

As stated in Ordering Paragraph 3 of Resolution E-4952, MCE will use the updated DEER assumptions, methods, and values for 2019 savings claims and 2020 planning, implementation and reporting.

Question: MCE is currently in the planning process. I'm concerned MCE is losing months of work with the ramp-up of programs. When will those programs launch?

MCE is working on contracts right now and looking to launch new programs in the next few months.

Program	***Anticipated Contract Execution***
Agricultural and Industrial (combined contract)	*March 1, 2019*
Residential Standalone Direct Install Program	*Design contract no later than February 15, 2019* *Implementation contract March 1, 2019*
Single-Family Comprehensive	*Pre-solicitation workshop February 21, 2019* *Solicitation March 4 – April 2, 2019* *Contract execution May 3, 2019*

Question: On slides 30 and 33, MCE mentions an expanded portfolio, but that only works if MCE is bringing in more savings and reducing costs. Please explain how an expanded portfolio brings up your cost-effectiveness?

Yes, MCE's greater population and diversity of our service area change when we expand. This creates more opportunity to do cost-effective savings in the expanded territory.

Question: On slides 30 and 33, MCE mentions focusing on cost-effective measures and targeted outreach? How is this different from MCE's past cost-effective strategies?

MCE was not required to be cost-effective in the past. We also allowed comprehensive projects and presented customers with a full range of opportunities which may or may not have been cost-effective. The new reality is to focus on offering more cost-effective measures. Additionally, MCE is revisiting its approach with different levels of service and not as much handholding for customers. This doesn't mean *refusing customers but fitting the customer into the most cost-effective option for them to meet everyone's needs.*

Question: Has the strategy change caused more single measure results than multi-measure? Is single measure part of your approach?

It's too early to say the results of these changes. MCE is hoping not to have only single measure programs and still wishes to offer comprehensive projects to customers.

Question: Which sectors do you plan to have performance-based incentives or programs for?

MCE is moving to performance-based contracts in all sectors. MCE will start NMEC and AMI in the residential sector and hopes to expand into commercial and beyond.

Question: What is changing in MCE's targeted outreach as a strategy to increase cost-effectiveness?

Working with AMI data and Open EE will allow us to do more targeted outreach based on historical program performance. MCE is also working with partners and implementers to help design offerings.

Question: How does MCE plan to track its business plan metrics?

The metrics MCE provided in its BP are comprehensive. By working with Open EE, MCE will use a subset of metrics to measure success and may even re-evaluate metrics to ensure they are capturing the success of our programs.

Question: Can MCE walk through the budgets per sector explaining each sector and where MCE is at in the contracting stage? There are concerns about starting a new program and ramp up time.

- *Agriculture and Industrial – MCE put out an RFQ at the end of last year and is in the process of speaking to respondents.*
- *Commercial – MCE has an existing program and is building out this program with existing implementers. MCE will also explore new models with implementers and make incremental changes over time.*
- *Residential Sector – MCE has a combination of new and existing programs. MCE put out an RFQ for Single Family Residential and currently speaking to respondents.*
- *Workforce, Education, and Training (WET) – MCE is in the process of putting together an RFQ to go out at the end of the month. MCE spent the month of December 2018 speaking with stakeholders to find any gaps considering that this is MCE's first time having WE&T initiatives as a separate program. MCE is expecting to have a rollout beginning of quarter two of this year.*

Question: RFQs and Solicitations – Is there an area where we can make a call to ask more people to come to the table for a stronger or larger pool of candidates?

In the past, MCE has had a limited pool of candidates because of our smaller budgets, but since our budget has grown, we have taken strategies to make the contracts more desirable. For example, putting Industrial and Agricultural under a single contract to make it more desirable to the market.

Question: What if no one comes to the table for the NMEC residential RFP?

We will do our best to engage with people already working on these types of programs and continue participating in the discussion around NMEC and clarifying pain points.

Question: Can you talk more about workforce development?

MCE is looking to workforce development agencies to propose and run programs in our community to help us achieve our business plan metrics. We're also working closely with PG&E to fill gaps of statewide programs. We don't want to put a lot of restraints on this program yet, and we are open to any proposals from electrical contractors and other stakeholder for their input on workforce, education, and development.

Question: Can you provide more details around the measures that you will be offering in programs to get a higher TRC? Will you include them in your report?

MCE will provide a list of measures in each implementation plan.

Question: How many vendors responded to MCE's Industrial and Agricultural RFQ?

Three vendors responded.

Question: Has MCE seen any results from its Seasonal Savings pilot program? Are there any opportunities to expand or get more aggressive with the program?

The Seasonal Savings pilot was originally a one-year pilot and moved to a two-year pilot as MCE expanded its territory. The 2nd year pilot has just ended. We are waiting for a final report from Nest.

Question: Is MCE thinking about having a deemed measure for smart thermostats as well to increase smart thermostats in your territory?

MCE is looking into this option, but we are worried about the details on double dipping with PG&E and not replicating what PG&E is doing.

Stakeholder Recommendations

Question: This is the CPUC's first workshop for Program Administrators that didn't make the 1.25 in the forecast ABAL. Stakeholders do you feel what was covered here was actually conducive to the goal of the workshop?

Stakeholder: It's valuable and useful. It takes investment for stakeholders to participate while there is so much going on. It's great to be able to share information and get in early enough to understand what's going on and make a difference.

Stakeholder: It would be helpful for MCE to provide more detail on collaboration with other Program Administrators. For example, MCE's SPOC model and collaboration with other Program Administrators.

Stakeholder: It would be helpful to have more detail on MCE's tool and how it will generate contractor competition with automated bids and how it was developed.

Appendix A: In-Person and Webinar Participation

In-Person Attendees

Last Name	First Name	Email Address
Quinn	Dennis	dquinn@joulesmart.com
Kinsey	Nate	nkinsey@cedmc.org
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Attendees via GoTo Webinar

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Arambula	Don	don.arambula@outlook.com

**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)

MOTION OF MARIN CLEAN ENERGY FOR PARTY STATUS

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January 15, 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)

MOTION OF MARIN CLEAN ENERGY FOR PARTY STATUS

Pursuant to Rule 1.4 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE") respectfully requests the Commission grant MCE party status in the above-captioned proceeding.

The Commission issued the *Assigned Commissioner's Scoping Memo and Ruling* ("Scoping Ruling") on December 21, 2018 in the instant proceeding. The Scoping Ruling commenced a new phase to continue the Commission's examination of Pacific Gas and Electric Company's ("PG&E") safety culture and organizational structure "to determine if the utility is positioned to provide safe electrical and gas service, and . . . review alternatives to the current management and operational structures of providing electric and gas service in Northern California."[1]

MCE is California's first operational Community Choice Aggregation ("CCA") program that began providing retail electricity service to customers in 2010. Since that time, MCE has expanded its CCA program to provide electricity generation services to over 470,000 customer accounts within PG&E's service territory. These communities include the counties of Marin, Napa, Contra Costa, and Solano, including the cities of Richmond, San Pablo, El Cerrito, Benicia, Walnut

[1] *Scoping Ruling* at p. 2.

Creek, Lafayette, Concord, Martinez, Oakley, Pinole, Pittsburg, and San Ramon, and the towns of Danville and Moraga. Recently, MCE filed an Implementation Plan with the Commission to certify expansion into unincorporated Solano County.

Among the issues within the scope of this phase is whether PG&E should provide only electric distribution and transmission services; which entities can and should be responsible for providing generation services in the event PG&E becomes a “wires only company”; whether to reconstitute PG&E as a Publicly Owned Utility; and whether PG&E’s gas and electric divisions should be split into separate companies. Each of the aforementioned issues affects MCE as a provider of retail electricity service to customers within PG&E’s service territory. Moreover, the issues affect MCE and its customers as recipients of transmission and distribution services from PG&E. The discussions and decisions made in this proceeding will directly impact MCE’s interests including the services MCE provides to its customers, the safe provision of transmission and distribution services to MCE’s customers, what MCE’s customers pay for and receive from PG&E, and the role of CCAs in changing electricity markets. As such, MCE requests party status to participate in, and inform, the discussions of PG&E’s potential operational changes, the safe provision of utility service, and what additional roles and responsibilities CCAs may fulfill in the event of material operational changes to PG&E’s organization.

Granting MCE’s request for party status will not prejudice any party or delay this proceeding because the instant phase has recently commenced with Opening Comments due on January 30, 2019. As such, MCE requests the Commission grant this Motion for Party Status.

SERVICE LIST

If granted party status in the above-captioned proceeding, MCE respectfully requests that the following person be added to the official service list as a party and that service of all notices, orders, and any and all other correspondence in this proceeding be sent via email only:

Elizabeth M. Kelly
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COUNSEL FOR MARIN CLEAN ENERGY

CONCLUSION

Based on the foregoing, MCE respectfully requests that the Commission grant its Motion for Party Status.

Respectfully submitted,

/s/ Nathaniel Malcolm

Nathaniel Malcolm
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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.	Rulemaking 17-09-20 (Filed September 28, 2017)

MARIN CLEAN ENERGY AND LS POWER NOTICE OF EX PARTE COMMUNICATION

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January 4, 2019

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-20 (Filed September 28, 2017)

**MARIN CLEAN ENERGY AND LS POWER
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") and LS Power hereby give notice of the following *ex parte* communication.[1] The communication was initiated by MCE and occurred on January 3, 2019 at approximately 11:00 am at the California Public Utilities Commission offices in San Francisco, California. The communication was between C.C. Song, MCE Senior Policy Analyst; Gregory Brehm, LS Power Director of Origination and Power Marketing; and David Peck, Advisor to President Picker. The meeting lasted approximately 30 minutes. The communication was oral and no written handout was given at the meeting.

In the meeting, Ms. Song and Mr. Brehm both stated that the Resource Adequacy ("RA") Track 2 Proposed Decision ("PD") would stifle the adoption of Energy Storage resources, as well as other Distributed Energy Resources. Additionally, Ms. Song discussed the potential rate increases that would be incurred if the PD was adopted, and Mr. Brehm discussed the storage market uncertainties that have been introduced after the issuance of the PD.

[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.

Respectfully submitted,

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January 4, 2019

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**BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-20 (Filed September 28, 2017)

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MARIN CLEAN ENERGY AND LS POWER
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") and LS Power hereby give notice of the following *ex parte* communication.[1] The communication was initiated by MCE and occurred on January 3, 2019 at approximately 1:00 pm via teleconference. The communication was between C.C. Song, MCE Senior Policy Analyst; Gregory Brehm, LS Power Director of Origination and Power Marketing; Anand Durvasula, Legal and Policy Advisor to Commissioner Randolph; and Joanna Gubman, Advisor to Commissioner Randolph. The meeting lasted approximately 20 minutes.The communication was oral and no handout was provided.

In the meeting, Ms. Song and Mr. Brehm both stated that the Resource Adequacy ("RA") Track 2 Proposed Decision ("PD") would stifle the adoption of Energy Storage resources, as well as other Distributed Energy Resources. Additionally, Ms. Song discussed the potential rate increases that would be incurred if the PD was adopted, and Mr. Brehm discussed the storage market uncertainties that have been introduced after the issuance of the PD.

[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.

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January 4, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 18-06-001 (Filed June 1, 2018)

COMMENTS ON ASSIGNED COMMISSIONER'S ALTERNATE PROPOSED DECISION OF 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

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Counsel to the Joint CCAs

February 11, 2019

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

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

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 18-06-001 (Filed June 1, 2018)

COMMENTS ON ASSIGNED COMMISSIONER'S ALTERNATE PROPOSED DECISION OF 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

Pursuant to Rule 14.3, 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")), submit these comments on Commissioner Guzman Aceves's Alternate Proposed Decision ("APD") regarding Pacific Gas & Electric Company's ("PG&E's") Energy Resource Recovery Account ("ERRA") application, filed June 1, 2018 ("Application").[1]

The APD corrects a critical error in the Proposed Decision ("PD") by revising the PD to adopt a "brown power true-up for subject year 2018."[2] Implementing the brown power true-up for 2018 follows the directives in Decision ("D.") 18-10-019 ("D.18-10-019" or the "PCIA

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[1] A.18-06-001, *Application of Pacific Gas and Electric Company (U 39 E) for 2019 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation* (June 1, 2018) ("Application").

[2] A.18-06-001, *Alternate Proposed Decision Adopting Pacific Gas & Electric Company's 2019 Energy Resource Recovery Account Forecast and Greenhouse Gas Forecast Revenue and Reconciliation*, p. 2, Conclusion of Law 1, Ordering Paragraph 1 (Jan. 22, 2019) ("APD").

Decision") in the PCIA docket, R.17-06-026, to establish a more accurate and transparent PCIA rate in a timely manner. Establishing 2018 as the subject year will prevent illegal cost-shifting to, and discriminatory treatment of, CCA customers by correcting a forecasting error that led to an overpayment of PCIA costs by unbundled customers in 2018. Unlike bundled customers, unbundled customers have no mechanism to correct their overpayment without the brown power true-up.

The Commission is right to establish an initial brown power true-up as soon as possible. D.18-10-019 repeatedly states that the brown power true-up should precede true ups of other PCIA-eligible resources like RPS and RA. As explained in more detail below, the APD's implementation of the brown power true-up is correct and should be adopted.

The Joint CCAs believe further changes to the APD regarding (1) transparency, (2) tax savings, and (3) PG&E's misallocation of Cost Allocation Mechanism ("CAM")-related cost will even more closely align the APD and PD with the law and sound ratemaking. We urge the Commission to adopt the APD as drafted with the additional changes described below and listed in the Appendix to ensure the mechanisms that make bundled customers whole apply similarly, and in the same timeframes, for unbundled customers.

I. The APD Properly Applies the Brown Power True-Up Adopted in D.18-10-019.

The "benchmark true-up process adopted in D.18-10-019," [3] Ordering Paragraph ("OP") Six, requires PG&E to "annually true-up their PCIA rates to reflect actual values realized in market transactions for the subject year for the Brown Power Index."[4] The Commission broadly defines "brown" power as non-RPS-eligible generation, meaning it includes large-scale

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[3] R.17-06-026, *Phase 2 Scoping Memo and Ruling of Assigned Commissioner*, p. 14 (Feb. 1, 2019) ("PCIA Scoping Memo"); D.18-10-019 at Ordering Paragraph 6.

[4] D.18-10-019 at Ordering Paragraph 6.

hydropower, nuclear power and cogeneration, as well as fossil-fired resources.[5] The brown power true-up "is, methodologically, a significant advance compared to [the Commission's] current practices."[6] Its purpose is to "increase the accuracy of the PCIA cost allocation between bundled and departing load customers,"[7] and "ensure that bundled and departing load customers pay equitably (*i.e.*, *pro rata*) for non-RA, non-RPS PCIA-eligible resources."[8]

PG&E's November Update failed to implement the true-up methodology established in D.18-10-019. In fact, PG&E did not squarely address the brown power true-up until it responded to discovery from the Joint CCAs, suggesting it would not implement the true-up until the subject year 2019.[9] If a true-up for subject year 2019 were included as part of the utility's 2019 ERRA compliance proceeding, or 2021 ERRA forecast proceeding, ratepayers would not see the results of the Commission's "significant advance" in the PCIA methodology until their 2021 rates—over two years after the date of the adoption of D.18-10-019.[10] PG&E cannot simply ignore an Ordering Paragraph in a Commission Decision, especially in a manner that would delay the implementation of that decision for years.[11] The APD correctly concludes "the subject year of the brown power true-up required by Ordering Paragraph 6 of D.18-10-019 commences

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5 *See* D.11-12-018 at pp. 17-25 (limiting the scope of the "green" adder to only include RPS-eligible generation, meaning all other power is "brown" power).

6 D.18-10-019 at 142.

7 *Id.* at Finding of Fact 15.

8 *Id.* at Conclusion of Law 16.

9 Exhs. Joint CCAs-19 and 22.

10 *See* A.18-0-6-001, *Comments on Proposed Decision of 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*, p. 5 (Dec. 17, 2018) ("Joint CCAs' Opening Comments on the PD").

11 *See* A.18-0-6-001, *Comments on Update to Pacific Gas and Electric Company's Prepared Testimony of 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*, p. 31 (Nov. 19, 2018) ("Joint CCAs' Comments on the November Update").

with 2018,"[12] and "[i]mplementing a true-up of 2018 brown power by this decision meets the requirements of the PCIA decision in a timely manner."[13]

The utility has accused the Joint CCAs of "cherry-picking," arguing that "[t]here is no indication anywhere in D.18-10-019 that the Commission intended to bifurcate the start of the true-up brown power from that of RA/RPS."[14] This argument ignores direct statements to the contrary in that decision, including:

(1) Page 121: "We have revised the true-up to be consistent with the conceptual approach recommended by the Joint Utilities, albeit without provisions to true up the **RA and REC components, which we determined should not be subject to true-up at this time**;"[15] and

(2) Page 141:"we have revised this APD to reflect our conclusion that, at least initially, **only brown power costs should be trued up**."[16].

Truing up the brown power benchmark in the manner D.18-10-019 prescribes is a much simpler exercise than truing up the RA and RPS benchmarks. D.18-10-019 expressly recognizes this, and the APD correctly moves forward with the brown power true-up first.[17]

Appropriately limiting its conclusions to subject year 2018,[18] the APD states it "may decide in the future to modify the brown power true-up method for subject years subsequent to

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12 APD at Finding of Fact 6.

13 *Id.* at 19, Conclusion of Law 5.

14 A.18-06-001, *Pacific Gas and Electric Company's (U 39 E) Reply Comments on the Proposed Decision*, p. 2 (Dec. 24, 2018) ("PG&E Reply Comments on the Proposed Decision").

15 D.18-10-019 at 121 (emphasis added).

16 *Id.* at 141 (emphasis added).

17 *Id.* at 141 (stating "The PCIA, at this time, cannot be relied upon to have the same result if RPS and RA are included in the true-up: the recorded "actuals" do not reflect the untransacted capacity used for bundled customer compliance or the untransacted RECs either used for compliance or banked for future use.").

18 APD at 19.

2018."[19] This limitation appropriately reflects that the true-up will evolve. The key point is that there is no need to wait for Phase 2 of the PCIA proceeding to run to its conclusion before implementing a true-up for 2018. Indeed, the scoping ruling in Phase 2 of the PCIA proceeding acknowledges a true-up process is already in place. That ruling states in pertinent part: "In the context of this proceeding, the Commission could instead decide to either (1) *leave in place the benchmark true-up process adopted in D.18-10-019*, (2) adopt a non-consensus recommendation submitted by one or more parties, or (3) adopt a true-up process of its own design."[20] That is, the true-up established in Ordering Paragraph Six of D.18-10-019 is already in place.

Ordering Paragraphs Seven and Eight in the PCIA Decision convey the Commission's intention to *later* true up RA and RPS-eligible resources, as well as "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."[21] This true-up will be based on the PABA structures currently being developed via advice letter, as well as any necessary revisions to the ERRA balancing account.[22] The APD is simply following the process set out in D.18-10-019.

By implementing a 2018 true-up, the APD prevents unjust discrimination against unbundled customers,[23] where only bundled customers currently receive the benefits of a

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[19] *Id.* at 20.

[20] PCIA Phase 2 Scoping Memo at 14 (emphasis added).

[21] D.18-10-019 at Ordering Paragraphs 7 and 8.3

[22] *Id.*

[23] Cal. Pub. Util. Code § 728; *Pacific Tel. & Tel. Co. v. Public Utilities Com.*, 401 P.2d 353, 361 (Cal. 1965) ("the primary purpose of the Public Utilities Act is to insure the public adequate service at reasonable rates without discrimination").

benchmark true-up. The Joint CCAs have initially estimated the difference between the forecasted and actual brown power benchmark to be $109 million for unbundled customers in 2018 (a 40.7% share of the indifference amount for that vintage).[24] No mechanism exists to make unbundled customers whole for this overpayment except for the brown power true-up adopted in D.18-10-019—and then only if 2018 is the subject year for that true-up.

The purpose of the PCIA Decision is, in part, to "adopt an annual true-up requirement to ensure that any forecast-related errors in the annual PCIA are reconciled and cost-shifting is prevented."[25] Deferring a true-up to a later date, and never truing up 2018 numbers, would fail to "ensure that bundled and departing load customers pay equally for PCIA-eligible resources,"[26] and, therefore, would have constituted an illegal cost shift the law does not permit.[27] The APD correctly concludes a true-up 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.'"[28]

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24 Joint CCAs' Opening Comments on PD at 4, n. 4.

25 D.18-10-019 at 62, 129.

26 *Id.*at 72.

27 Cal. Pub. Util. Code § 365.2 (stating "The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."); Cal Pub Util Code § 366.2(f)(2) (stating "A retail end-use customer purchasing electricity from a [CCA] pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following … any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer's purchases of electricity from the[CCA] through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.").

28 APD at 19 (citing D.18-10-019 at Conclusion of Law 16).

II. The Record Supports the APD's Conclusions.

In Exhibits Joint CCAs-19 and 22, PG&E explained its view of how the brown power true-up operates, albeit in a manner that attempts to partially revise the approach adopted in Ordering Paragraph Six, stating:

> [T]he "Brown Power [MPB] true-up" will involve recording actual revenues received in the California Independent System Operator (CAISO) market for the PCIA-eligible generation resources that are bid into the CAISO market. … The true-up of the Brown Power MPB will involve recording actual net revenues received in the CAISO market for the PCIA-eligible generation resources that are bid into that market. That is, each PCIA-eligible generation resource bid into the CAISO market will receive revenues and charges for energy and ancillary services and the net revenues for each PCIA-eligible resource will be recorded to the applicable PABA subaccount, which effectively is the true-up for the Brown Power MPB.[29]

PG&E's approach is very similar to the approach adopted in the APD and discussed in the Joint CCAs' comments.[30]

The substantive difference between the APD and PG&E's discovery response can be found in the term "net revenues."[31] However, the term "net revenues" does not appear in Ordering Paragraph Six,[32] so it makes sense the Commission would exclude the concept from the

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29 Exhs. Joint CCAs-19 and 22.

30 *Compare* Exhs. Joint CCAs-19 and 22 *to* APD at 19-20, Ordering Paragraph 6 *and* Joint CCAs' Comments on the PD at 4, n. 4.

31 PG&E's mention of the Portfolio Allocation Balancing Account ("PABA") in its discovery response does not constitute a substantive difference. As the utility itself acknowledges, the PABA accounting structure is a "non-substantive" revision to how costs are tracked—meaning it should not impact the value of the true-up, *i.e.*, the difference between the forecasted and actual benchmark values. *See* Exh. PG&E-6, 7:6-15. The Commission stated "If the Joint Utilities' proposed balancing account structure would aid in collecting information necessary to eventually true up those components, we authorize each utility to establish the necessary structure." D.18-10-019 at 121.

32 D.18-10-019, Ordering Paragraph 6 (requiring to 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.").

APD. Indeed, the term "net [CAISO] revenues" only appears in Ordering Paragraph Seven, which, along with Ordering Paragraph Eight, sets the stage for a fuller iteration of the true-up, as explained above.[33] Thus, the APD's approach is the correct one.

III. The APD's Focus on Truing Up Only the Market *Value* of the Brown Power Benchmark, and Not Costs, Correctly Implements D.18-10-019.

D.18-10-019's brown power true-up only includes the market value side of the equation and not the total portfolio cost.[34] Ordering Paragraph Six states the IOUs "shall annually true-up their PCIA rates to <u>*reflect actual values realized in market transactions*</u> for the subject year for the Brown Power Index."[35] The emphasized language conveys a clear intent to only address "market transactions", *i.e.*, the market value portion of the indifference amount, and not the cost portion. Similar to the term "net CAISO revenues", discussed *supra*, the phrase "generation resource costs" only appears in Ordering Paragraph Seven's framework for the *next* iteration of the PCIA true-up, and it would be premature to adopt it here. PG&E's request to also include billed PCIA revenues and allocation to each vintage group also fails for the same reason—those are intended to be implemented as part of the PABA true-up.[36]

IV. The Joint CCAs Believe Additional Points in the APD Should be Addressed.

As well-reasoned as the APD is with regard to the brown power true-up, the Joint CCAs believe revisions to a handful of the conclusions that remain unchanged from the PD will better align the APD with the law and sound ratemaking. The Scoping Ruling for Phase 2 of the PCIA docket indicates the utility will again be making modifications to the PCIA as part of the

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33 *Id.,*,Ordering Paragraphs 7 and 8.

34 *Id.,* Ordering Paragraph 6; *see also* D.18-10-019 at 138, 142.

35 *Id.* at Ordering Paragraph 6 (emphasis added).

36 *See* D.18-10-019 at Ordering Paragraph 7.

November Update in its 2020 ERRA forecast proceeding.[37] The current status of the instant proceeding underscores the difficulty of amending the PCIA in a short timeframe and supports modifying PG&E's 2020 forecast proceeding as part of the APD in anticipation of these difficulties.

PG&E argues no changes are necessary and incorrectly states the Joint CCAs' requests are tied to the special circumstances surrounding D.18-10-019.[38] The Joint CCAs have consistently raised these issues, even in years when no special circumstances existed,[39] and our request is not to "alter the structure of ERRA forecast proceedings generally" for all IOUs within this proceeding.[40] The Joint CCAs simply hope for Commission guidance for a forum in which more concrete procedural mechanisms, such as the following, might be adopted for PG&E's ERRA processes going forward:[41]

- Planned workshops soon after the application is filed in which PG&E would explain any significant changes in methodology or policy underlying the application,
- Use of the modified non-disclosure agreement from the PCIA proceeding to allow counsel and CCA personnel access to confidential workpapers to increase collective understanding and transparency,
- Expedited discovery timelines,

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[37] PCIA Phase 2 Scoping Memo at 6.

[38] PG&E Reply Comments on the Proposed Decision at 5.

[39] *See, e.g.,* A.15-06-001, *Sonoma Clean Power Comments on Proposed Decision*, pp. 3-10 (Dec. 3, 2015).

[40] APD at 16.

[41] A.18-06-001, *Opening Brief of 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*, pp. 21-24 (Oct. 2, 2018); A.18-06-001, *Reply Brief of 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*, p. 3 (Oct. 16, 2018); Joint CCAs' Comments on the November Update at 31-34.

- A procedural schedule that begins sooner, including scheduling of prehearing conferences closer to the application date, and/or

- A required update to the Annual Energy True-up advice letter ("AET") concurrent and consolidated with the November Update (or elimination of the AET altogether) so that CCAs know the rates their customers will soon pay.

These are reasonable—and easily enacted—requests when compared with the substantial impact the ERRA proceedings have on millions of Californians. Even if a broader discussion on these issues is not initiated, the Joint CCAs request the APD be revised to require changes to PG&E's 2020 ERRA forecast proceeding in order to prepare for complications likely to arise from further changes to the PCIA calculation scheduled to occur in Phase 2 of R.17-06-026.

Further, the Joint CCAs believe the APD continues to fall short on other issues arising from the November Update and related discovery, including:

- PG&E should be required to develop a mechanism to include tax savings in unbundled customers' 2019 PCIA rates since bundled customers will receive such a benefit in their 2019 generation rates according to PG&E's AET advice letter;[42] and

- While the Joint CCAs appreciate the revision to the PD (and included in APD) that the CAM-related error may be corrected in the 2018 Compliance proceeding, we urge the Commission to address it here. If not, we respectfully request the APD be clarified to state that all affected customers, including unbundled customers, will benefit simultaneously from a refund related to PG&E's accounting errors.[43]

These requested changes are explained in more detail in the Joint CCAs' Opening Comments on the PD and apply equally to the APD.

V. Conclusion

The Joint CCAs thank Commissioner Guzman Aceves, her staff, Energy Division Staff and ALJ Wildgrube for their efforts in resolving the complex issues raised in this docket. We respectfully request the Commission revise the APD along the lines enumerated in the attached

[42] Joint CCAs' Opening Comments on the PD at 10-11.

[43] *Id.* at 13-14.

Appendix, which reflect the yet-to-be-adopted revisions to the PD's Findings of Fact, Conclusions of Law and Ordering Paragraphs submitted in the Joint CCAs' Opening Comments on the PD.

Dated: February 11, 2019

Respectfully submitted,

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APPENDIX

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, the Joint CCAs offer the following index of recommended changes to the *Alternate Decision Adopting Pacific Gas And Electric Company's 2019 Energy Resource Recovery Account Forecast And Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation*, including proposed changes to the Findings of Fact, Conclusions of Law and Ordering Paragraphs. The Joint CCAs proposed revisions appear in underline and strike-through.

Findings of Fact

5. A petition for modification of D.17-05-013, PG&E's 2017 General Rate Case is pending to address reduction of the revenue requirement due to the Tax Cuts and Jobs Act of 2017, the benefits of which will be allocated to bundled customers 2019 rates via the AET but not to unbundled customers' 2019 rates.

7. It is reasonable to value brown power, Resource Adequacy capacity and Renewable Portfolio Standard eligible energy in excess of demand and sold via multi-year contracts using the Market Price Benchmark.

[X]. Revisions to the current ERRA framework will foster the Commission's and customers' ability to understand, plan for and establish just and reasonable rates.

[X]. This decision's conclusion that the calculation of the PCIA rate continue to be determined 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 obviates the issue raised by the Joint CCAs regarding the omission of 6,440 GWh of load in the "Legacy UOG" vintage in the November Update.

Conclusions of Law

2. The multi-year sales of brown power, Resource Adequacy capacity and Renewable Portfolio Standard eligible energy should be valued using the Market Price Benchmark.

3. It is reasonable to address misallocated CAM related costs as part of this 2019 ERRA forecast proceeding ~~in the 2019 ERRA compliance and 2020 ERRA forecast proceedings~~.

4. It is reasonable to include ~~defer~~ in the PCIA calculation for this 2019 ERRA forecast proceeding a one-time adjustment in recognition of potential tax savings realized from application of the Tax Cut and Jobs Act ~~because they are not yet approved by the Commission~~.

[*Alternative 1*] [X]. Revisions to the current ERRA framework should be considered in a Phase 2 of this proceeding that is consolidated with A.18-05-003 (Southern California Edison's 2019 ERRA forecast proceeding) and A.18-04-004 (San Diego Gas & Electric's 2019 ERRA forecast proceeding).

[*Alternative 2*] [X]. It is reasonable to require PG&E to include in its 2020 ERRA forecast application and proposed schedule (1) a planned workshop soon after the application is filed in which the utility will explain any significant changes in methodology or policy underlying the application, (2) use of the modified non-disclosure agreement from the PCIA proceeding R.17-06-026, (3) expedited discovery timelines, (4) a longer procedural schedule that still allows for a decision by January 1, 2020, (5) an update to the AET concurrent and consolidated with the November Update, and (6) a prehearing conference date prior to July 15, 2019.

Ordering Paragraphs

[*Alternative 1*] [X]. Revisions to the current ERRA framework shall be considered in a Phase 2 of this proceeding that is consolidated with A.18-05-003 (Southern California Edison's 2019 ERRA forecast proceeding) and A.18-04-004 (San Diego Gas & Electric's 2019 ERRA forecast proceeding).

[*Alternative 2*] [X]. PG&E shall include in its 2020 ERRA forecast application and proposed schedule (1) a planned workshop soon after the application is filed in which the utility will explain any significant changes in methodology or policy underlying the application, (2) use of the modified non-disclosure agreement from the PCIA proceeding R.17-06-026, (3) expedited discovery timelines, (4) a longer procedural schedule that still allows for a decision by January 1, 2020, (5) an update to the AET concurrent and consolidated with the November Update, and (6) a prehearing conference date prior to July 15, 2019.

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

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 18-06-001 (Filed June 1, 2018)

JOINT CCAS' REPLY COMMENTS ON ALTERNATE PROPOSED DECISION

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February 15, 2019

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

JOINT CCAS' REPLY COMMENTS ON ALTERNATE PROPOSED DECISION

Pursuant to Rule 14.3, the Joint CCAs submit these reply comments on Commissioner Guzman Aceves' APD regarding PG&E's ERRA Application.[1] PG&E's Opening Comments attempt to obscure the APD's clear reasoning and sow doubt regarding the accuracy, practicality, and legality of the true-up adopted therein. This attempted obfuscation should not sway the Commission.[2]

I. D.18-10-019 Contemplated an Immediate True-Up of the Brown Power Benchmark.

PG&E's Opening Comments attempt to cloud the simple timeline and process established in D.18-10-019. Ordering Paragraph ("OP") 6 in that decision 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."[3] The Commission recognized the brown power true-up is a simpler task than the RA or RPS true-ups,[4] which require further discussion "in the scope of Phase 2 of [the PCIA] proceeding with the goal of developing a true up process for RA and RPS *by the end of 2019*."[5] The Commission concluded that, "at least initially," only the brown benchmark would be trued up, and "the RA and REC components … should not be subject to true-up *at this time*."[6] This clear bifurcation in timing—established outside of this docket—contradicts the basis for most of PG&E's objections.

The other basis for PG&E's objection to the APD amounts to an argument the PCIA Decision does not state the exact words "in 2018."[7] However, D.18-10-019's directives only make sense if 2018 is the subject year of the initial true-up. The Commission has "the goal of developing a true up process

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[1] Acronyms used herein have the same meaning as those in the Joint CCAs' Opening Comments on the APD.
[2] PG&E raises the same arguments it has previously regarding its new treatment for (1) multi-year sales of RA capacity, RPS energy and brown power and (2) allocating the PCIA using non-system-level billing determinants. Both the APD and the Proposed Decision correctly conclude these changes are inappropriate for this proceeding. PG&E cannot meet its burden to demonstrate its calculations and entries for the PCIA are "in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes" by proposing new rules and regulations. *See* A.18-06-001, *Assigned Commissioner's Scoping Memo and Ruling*, p. 3 (Aug. 16, 2018). PG&E's comments do not raise any new points so the Joint CCAs do not address them again here but respectfully request the Commission reject the proposals based on the reasoning in prior pleadings, comments and the APD.
[3] D.18-10-019 at Ordering Paragraph ("OP") 6 (emphasis added).
[4] *Id.* at 141 (stating "The PCIA, at this time, cannot be relied upon to have the same result if RPS and RA are included in the true-up: the recorded "actuals" do not reflect the untransacted capacity used for bundled customer compliance or the untransacted RECs either used for compliance or banked for future use.").
[5] *Id.*at 142. (emphasis added) (stating further: "While a true-up of all attributes of utility portfolios would provide the most accurate PCIA, there are complexities with a true-up of untransacted capacity and RECs that need further record development to resolve.").
[6] *Id* at 126, 141 (emphasis added). Please note: the Joint CCAs' Opening Comments on the APD erroneously cited to page 121 for the latter quotation above instead of the correct page 126.
[7] *See, e.g.,* PG&E Opening Comments on APD at pp. 3-4, 6.

for RA and RPS by the end of 2019."[8] President Picker's PCIA Phase 2 Scoping Ruling confirms this approach, prioritizing the RA/RPS true-ups and stating it "should be resolved *in time to be implemented in the Joint Utilities' respective 2020 ERRA Forecast Updates in early November 2019*."[9] If the second iteration of the true-up is implemented in the 2020 forecast proceeding, then it will go into effect for 2020 rates, meaning 2019 will be the subject year of that true-up. If 2019 is the subject year of the RA/RPS true-up, then it follows D.18-10-019's "initial" true-up of the brown benchmark "at this time" would target the prior year, *i.e.*, 2018. Otherwise, the true-ups would be implemented simultaneously; the Commission's intent to bifurcate the implementation of the true-up would be negated; and the PCIA Decision would conflict with itself. Clearly, the Commission did not intend such a result.

This context also helps clarify the purpose of OPs 7 and 8, which PG&E argues in its comments must be read holistically with OP 6.[10] We agree the OPs should be read holistically—including with the rest of the decision. In the context of the entire decision, these OPs establish the scope of each step within the bifurcated process. OP 6 requires an *immediate* true-up of the brown benchmark. OPs 7 and 8 set 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, as well as the other components listed in OP 7, *i.e.*, the "billed revenues, generation resource costs, net [CAISO] market revenues associated with energy and ancillary services, and revenues associated with the renewable energy Adder and the [RA] capacity in each vintaged portfolio."[11] That is, OPs 7 and 8 address the RA and RPS true-up and associated mechanisms, including related revisions to the ERRA balancing account and the PABA structures currently being developed via advice letter.[12] Indeed, the very purpose of the PABA is to "aid in collecting information necessary to *eventually* true-up [the RA and REC] components."[13]

The APD follows this process set out in D.18-10-019. It appropriately limits its conclusions to subject year 2018,[14] and it states the Commission "may decide in the future to modify the brown power true-up method for subject years subsequent to 2018."[15] As such, the Commission should implement OP 6 in this proceeding and adopt the brown power true-up as presented in the APD.

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[8] D.18-10-019 at 142 (emphasis added).
[9] R.17-06-026, *Phase 2 Scoping Memo and Ruling of Assigned Commissioner*, p. 3 (Feb. 1, 2019).
[10] PG&E Opening Comments on APD at 4.
[11] D.18-10-019 at OP 7.
[12] *Id.* at OPs 7 and 8.
[13] *Id.* at 126 (emphasis added).
[14] APD at 19.
[15] *Id.* at 20.

II. PG&E Admits Brown Power Costs Were Shifted to Departing Load Customers.

At various points in its comments the utility suggests the *initial* true-up must include one, a combination, or all of the following: actual net CAISO market revenues, the PABA structures, actual generation costs, an updated RA benchmark, actual billed PCIA revenues, an updated RPS benchmark, actual generator volumes, and the actual prices for those volumes.[16] Nowhere in comments, testimony, briefs or discovery responses does PG&E offer a clear definition or explanation regarding the scope of these terms or their individual impact on the PCIA. The utility instead offers four different values for the true-up based on data "for illustrative purposes," as a "preliminary estimate," and in a manner "not intended to be used as proposed totals for 2019 ratemaking"—in comments with no supporting workpapers.[17]

PG&E's listing of the amounts due to unbundled customers under various methods amount to an admission that brown power costs were shifted to those customers in 2018.[18] The key remaining question is the amount of that cost shift, for which the APD sets the methodology but rightly leaves final calculations to an advice letter process. The APD's approach for an initial true-up is reasonable in light of D.18-10-019's conclusion to "adopt, at least for now," only a limited true-up based on "the difference between the forecast and actual market prices, sales volumes and PCIA revenue collections,"[19] while recognizing OP 7's requirement, quoted *supra*, that consideration of the latter issue be delayed until the next iteration of the true-up.[20] The APD also builds off the record in this proceeding, rejecting a part of the utility's proposal for a similar true-up that would have included net CAISO revenues—a component, similar to the PCIA revenues, that is included in the more robust true-up in OP 7, but not the immediate true-up reflected in OP 6.[21] The APD's approach is reasonable and should be adopted.

III. PG&E Has the Data It Needs to Conduct the True-Up.

PG&E states implementation of the true-up is "impossible" because it does not follow the PABA structure or the PCIA standard templates.[22] Neither is accurate. PG&E already has the data necessary

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[16] *See, e.g.,* PG&E Opening Comments on APD at 5-10.
[17] *Id.* at 9.
[18] *Id.*
[19] D.18-10-019 at 138, 142.
[20] *Id* at OP 7.
[21] *Id* at OP 6.
[22] PG&E Opening Comments on APD at 4, 8 (stating "It is impossible for PG&E to use the average price of brown market power for the brown power true-up but not update the RPS values while remaining in compliance with the standard template.").

to true up all of 2018 since such data is available 12 business days after the end of the subject year.[23] The PABA is a "non-substantive" accounting change—meaning it should not impact the value of the true-up.[24] Further, PG&E's argument that it cannot calculate the change in rates resulting from the brown power true-up is belied by its own estimations of the APD's impacts within its Opening Comments. There is no practical reason 2018 should not be the "subject year" for the first true-up.

IV. The APD is on Firm Legal Footing.

PG&E asserts the APD is contrary to state law requiring indifference, ignoring the IOUs' own arguments in R.17-06-026 insisting "a true-up is absolutely necessary" to avoid a cost shift.[25] The PCIA Decision notes it was the IOUs recognizing that while "it would be relatively straightforward to 'true-up' for energy sales, revenues, and generation volumes after the fact (because energy is transacted transparently in a liquid market)…the same is not true of RA and [Renewable Energy Credits]."[26] That is, D.18-10-019 balances *the IOUs'* desire for a true-up with the complexity of the RA/RPS true-up via a bifurcated approach where the brown power benchmark is trued up first. PG&E's argument here on indifference is tantamount to saying D.18-10-019 contravenes the law, which is an issue for rehearing in R.17-06-026—not an ERRA proceeding limited to compliance with prior orders.[27]

Further, adopting the APD does not constitute retroactive ratemaking. PG&E's thinly veiled implications regarding what it calls the "retroactive" application of D.18-10-019 ignore that decision, the mechanics of the brown power true-up, and the law.[28] First, D.18-10-019 adopted the true-up, not the APD. Therefore, any retroactivity challenge is an issue for rehearing in R.17-06-026, not in this proceeding. Second, the true-up functions in the same prospective manner, and is rooted in the same legal doctrine, as other true-up mechanisms the Commission has adopted, where customers pay an adjusted rate in one year (here, 2019) for forecast-related variances from the subject year (here, 2018).[29]

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[23] California System Operator, *Settlement and Billing Business Practice Manual*, § 2.3.2 (July 24, 2018) (also stating final settlement data is available within 55 business).
[24] D.18-10-019 at 126; *see also* Exh. PG&E-6, 7:6-15 (stating the PABA is non-substantive).
[25] PG&E Opening Comments on APD at 5; D.18-10-019 at 67, n.143.
[26] D.18-10-019 at 67.
[27] *See, e.g.*, D.18-01-009 at 10; A.13-05-015 Scoping Ruling, pp. 3-4 (September 12, 2013); A.17-06-005 Scoping Ruling, pp. 3-4 (August 24, 2017); A.18-06-001, *PG&E Reply to Protests and Responses*, pp. 2-3 (July 16, 2018); A.17-06-005, *Opening Brief of PG&E*, p. 21 (Oct. 16, 2017).
[28] *See, e.g.,* PG&E Opening Comments on APD at 3-4, 6.
[29] *See, e.g.,* D.18-10-019 at 141 (explaining the ERRA true-up, which only bundled customers currently enjoy: "bundled ratepayers pay the forecast ERRA rate for a year, the actual costs and revenues are tracked, and the same ratepayers pay a new ERRA rate the next year that is adjusted for any forecast-related variances in the prior year").

Even if the Commission concludes the APD is retroactive in effect, the Commission and the Supreme Court of California have determined in strikingly similar cases that an adjustment of rates via an ERRA-like proceeding is not retroactive ratemaking. In *So. Cal. Edison v. CPUC*, the Commission revised the calculation methodology for a fuel adjustment clause and applied the revised methodology to rates from the previous *three* years.[30] Applying the revised methodology revealed an over-collection that was then recovered in the following years' rates.[31] The court ruled the Commission did not engage in retroactive ratemaking under §728 due, in part, to the fact the new rates were adopted outside of a general rate case and intended to recover and pass through the utility's "dollar for dollar" expenses as opposed to impacting its profitability.[32] Similarly, the APD applies a formulaic mechanism to recover PCIA over-collections for generation costs in 2018 that do not impact IOU profitability.

Perhaps even more analogous is *Cal. Mfrs. Ass'n v. CPUC.*[33] There, the Commission revised a rate allocation methodology within an "offset proceeding."[34] The difference in rates after applying the revised methodology to prior-approved rates was recovered prospectively as "surcharges" to one customer group and "rebates" to another customer group.[35] The court determined the rule in *So. Cal. Edison* also "applies to surcharges based on recalculations of costs and their allocation," and the Commission's decision was not retroactive ratemaking.[36] Likewise, the APD remedies the 2018 over-collection between one group of customers (unbundled customers) and another (bundled customers).

Notably, PG&E itself stops short of expressly arguing the APD is retroactive ratemaking.

V. Conclusion

We respectfully request the Commission adopt the APD as revised in Appendix A to the Joint CCAs' Opening Comments on the APD.

Dated: February 15, 2019

Respectfully submitted,

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[30] *So. Cal. Edison v. Cal. Pub. Util. Comm'n*, 20 Cal.3d 813, 822-825 (Mar. 23, 1978).
[31] *Id.*
[32] *See* Cal. Pub. Util. Code § 728; *So. Cal. Edison* at 818-819, 830.
[33] *Cal. Mfrs. Ass'n v. Cal. Pub. Util. Comm'n*, 24 Cal. 3d 251 (May 16, 1979).
[34] *Id.* at 255-257.
[35] *Id.* at 261-262.
[36] *Id.*

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February 20, 2019

Energy Division
California Public Utilities Commission
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Re: Joint CCAs' Protest to PG&E Advice Letter 5376-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, and Silicon Valley Clean Energy (collectively, the Joint Community Choice Aggregators ("Joint CCAs")) protest Pacific Gas and Electric Company's ("PG&E's") Advice Letter 5376-E-A ("Advice Letter" or "AL").[1]

The Joint CCAs protest the Advice Letter on the grounds the relief requested creates unreasonable and unnecessary inaccuracy and instability in both bundled and unbundled customers' rates by (1) basing Annual Electric True-up ("AET") rate changes on stale sales forecast data from early June 2017 and (2) bifurcating the AET process, resulting in two separate and substantial rate changes within months of each other.[2] The Joint CCAs respectfully request the Commission deny the requested relief and order PG&E to implement one, consolidated AET once a final decision has been reached in Application ("A.") 18-06-001.

The Advice Letter's primary request is to update the revenue requirements and rate changes in its preliminary AET, advice letter 5376-E.[3] The AL will increase the utility's electric revenue by $259.5 million compared to revenue at present rates,[4] resulting "in a 2.2 percent increase in PG&E's system average bundled electric rate and a 1.3 percent increase in PG&E's system average rate for Direct Access (DA) and [CCA] customers, whose average rates exclude energy supply charges because these customers procure supplies from third-party service providers."[5]

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[1] General Order No. 96-B, General Rules § 7.4.2. As an initial matter, the Joint CCAs believe PG&E's request for a five-day protest deadline for a filing of this magnitude is unreasonable.

[2] *Id.* §7.4.2(6).

[3] PG&E Advice Letter 5376-E-A at 1-2 ("Supplemental AET").

[4] *Id.* at 2.

[5] *Id.*

The purpose of the AET is to implement rate changes from a number of different proceedings, including PG&E's ERRA forecast proceeding.[6] Typically, the AET simultaneously implements any approved changes from these proceeding to both distribution rates, *i.e.*, the rates that both bundled and unbundled customers pay for delivery and other shared services, and generation rates, *i.e.*, the rates bundled customers pay for energy supply PG&E has procured.[7]

Here, a number of rate changes presented in the preliminary AET are still pending before the Commission, notably the rate components in the ERRA forecast proceeding. The utility states it "will implement those changes as soon as practicable after the 2019 ERRA Forecast final decision is issued by the Commission."[8] The result is a bifurcated process where "PG&E's 2019 AET will be implemented across two submittals: (1) this supplemental advice letter that includes non-ERRA components, and (2) a subsequent submittal that incorporates the 2019 ERRA Forecast final decision. The overall 2019 AET will be the cumulative change from both these submittals."[9]

Stated another way, PG&E proposes within the Advice Letter a new AET process that now includes:

- An initial revision to bundled customers' generation rates on March 1;
- A revision to both bundled and unbundled customers' distribution rates on March 1;
- A second revision to bundled customers' generation rates at a later date, pending conclusion of the ERRA forecast proceeding;
- A revision to the Power Charge Indifference Adjustment ("PCIA") rate unbundled customers pay at a later date; and
- Further revisions to other rates at a later date from both the ERRA and non-ERRA proceedings, such as the implementation of specific, updated residential baseline quantities planned for May 1, 2019 as a result of D.18-08-013.[10]

The bottom line is both bundled and unbundled ratepayers will experience two substantial rate changes in 2019 between March 1 and the timing of the utility's second AET submittal, diminishing rate stability and increasing the risk of customer confusion.

In addition, the utility proposes to use stale data to enact the changes. The AL states the consolidation of electric rate changes, and the reflection of revenue requirement changes and

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6 *See* PG&E Advice Letter 5376-E, pp. 1-3 (September 4, 2018) ("Preliminary AET").
7 *See id.* at 4-18.
8 Supplemental AET at 1-2.
9 *Id.*
10 PG&E Advice Letter 5429-E, p. 3 (approved by Energy Division on Dec. 17, 2018 and effective Jan. 1, 2019).

balancing account amortizations, within the AL will be "based on the adopted sales forecast for 2018, authorized in Decision ("D.")18-01-009."[11] That is, the utility will implement the AL using forecast—not actual—data from *June 2017* that was adopted nearly 14 months before the Advice Letter's effective date and does not reflect expected conditions in 2019. Such an approach makes little sense, especially given the utility's request for an expedited five-day protest period that ends *the day before* a final decision is anticipated in the ERRA forecast proceeding – the very docket in which the 2019 sales forecast will be set based on more recent data.

PG&E has offered no compelling reason to justify whipsawing both bundled and unbundled customers through the rate changes that will result from this more complex and less accurate approach. The Joint CCAs sent PG&E a data request (attached hereto) yesterday, February 19, the business day following PG&E's filing, asking "why PG&E did not wait until a final decision in A.18-06-001 to file its AET." [12] PG&E stated in response that it is simply "implementing the 2019 [AET] consistent with its proposal in initial Advice Letter 5376-E."[13]

No further explanation, let alone a compelling one, has been given regarding the urgency or need for a March 1 date. The lack of justification is striking when (a) the ERRA forecast proceeding at the core of so much of the AET is still outstanding, and (b) the March 1 date in the preliminary AET Advice Letter 5376-E clearly assumes a decision had been reached before that date in the ERRA forecast proceeding.[14]

PG&E's explanation is insufficient when hundreds of millions of dollars in rate changes are at stake. Indeed, the net result of using older data—and bifurcating the AET—is unclear at this point, meaning PG&E's proposal may very well benefit unbundled customers in the near term.[15] However, the Joint CCAs do not believe this potential benefit or PG&E's explanation justify the instability all customers would face as a result of the Advice Letter.

The Joint CCAs respectfully request the Commission dispose of the AL by denying the requested relief and ordering PG&E to implement one, consolidated AET once a final decision has been reached in A.18-06-001.

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11 Supplemental AET at 2.

12 PG&E Response to Joint CCAs Data Request 004-Q03(a) (attached).

13 *Id.*

14 *See* Preliminary AET at 1-3.

15 PG&E Response to Joint CCAs Data Request 004-Q03(c) (attached).

Respectfully submitted,

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Service Lists of R.17-06-026 and A.18-06-001

ATTACHMENT

PACIFIC GAS AND ELECTRIC COMPANY
Annual Electric True-Up Advice Letter 2019
Data Response

PG&E Data Request No.:	JointCCA_004-Q03		
PG&E File Name:	AnnElecTrue-UpAdviceLetter2019_DR_JointCCA_004-Q03		
Request Date:	February 19, 2019	Requester DR No.:	First Set
Date Sent:	February 19, 2019	Requesting Party:	Joint CCA's California Public Utilities Commission (CPUC) /East Bay Community Energy (EBCE) /Marin Clean Energy (MCE)/Monterey Bay Community Power (MBCP)/Peninsula Clean Energy (PCE)/Pioneer Community Energy (Pioneer)/Silicon Valley Clean Energy (SVCE)/Sonoma Clean Power (SCP)
PG&E Sender:	Angelia Lim	Requester:	Tim Lindl

SUBJECT: **<u>ADVICE LETTER 5376-E-A</u>**

QUESTION 3

Please reference pages 1-15 of PG&E Advice Letter 5376-E-A.

a. Please explain why PG&E did not wait until a final decision in A.18-06-001 to file its AET.

b. Please confirm that both bundled and unbundled ratepayers will experience two rate changes in 2019 due to the bifurcation of the AET.

c. Please explain the net impact, *i.e.*, an interim increase or an interim decrease, on both (i) bundled customers' rates and (ii) and unbundled customers' rates as a result of bifurcating the implementation of PG&E Advice Letter 5376-E-A.

ANSWER 3 (a)

PG&E is implementing the 2019 Annual Electric True-Up (AET) consistent with its proposal in initial Advice Letter 5376-E [1] which stated that it would implement the AET effective March 1, 2019 if final decisions of The Joint Utilities applications to review, revise, and consider Alternatives to the Power Charge Indifference Adjustment (PCIA) in response to the Order Instituting Rulemaking (R.) 17-06-026 (PCIA OIR); and 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas (GHG) Forecast Revenue and Reconciliation

[1] See Advice 5376-E submitted on September 4, 2018, page 1

Application (A.) 18-06-001 (2019 ERRA Forecast), are not issued by October 25, 2018, and December 13, 2018, respectively (See page 2, Advice 5376-E-A).

ANSWER 3 (b)

Yes, both system average rates of bundled and unbundled customers may change from that effective March 1, 2019, when PG&E implements rate and revenue changes due to the 2019 ERRA Forecast and any other decisions, authorized by the California Public Utilities Commission (CPUC or Commission) and Federal Energy Regulatory Commission (FERC).

ANSWER 3 (c)

Due to the 2019 ERRA Forecast and any other decisions still pending before the Commission, PG&E is unable to provide the information at this point in time.

FILED
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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)

MOTION OF MARIN CLEAN ENERGY FOR PARTY STATUS

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January 15, 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)

MOTION OF MARIN CLEAN ENERGY FOR PARTY STATUS

Pursuant to Rule 1.4 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE") respectfully requests the Commission grant MCE party status in the above-captioned proceeding.

The Commission issued the *Assigned Commissioner's Scoping Memo and Ruling* ("Scoping Ruling") on December 21, 2018 in the instant proceeding. The Scoping Ruling commenced a new phase to continue the Commission's examination of Pacific Gas and Electric Company's ("PG&E") safety culture and organizational structure "to determine if the utility is positioned to provide safe electrical and gas service, and . . . review alternatives to the current management and operational structures of providing electric and gas service in Northern California."[1]

MCE is California's first operational Community Choice Aggregation ("CCA") program that began providing retail electricity service to customers in 2010. Since that time, MCE has expanded its CCA program to provide electricity generation services to over 470,000 customer accounts within PG&E's service territory. These communities include the counties of Marin, Napa, Contra Costa, and Solano, including the cities of Richmond, San Pablo, El Cerrito, Benicia, Walnut

[1] *Scoping Ruling* at p. 2.

Creek, Lafayette, Concord, Martinez, Oakley, Pinole, Pittsburg, and San Ramon, and the towns of Danville and Moraga. Recently, MCE filed an Implementation Plan with the Commission to certify expansion into unincorporated Solano County.

Among the issues within the scope of this phase is whether PG&E should provide only electric distribution and transmission services; which entities can and should be responsible for providing generation services in the event PG&E becomes a "wires only company"; whether to reconstitute PG&E as a Publicly Owned Utility; and whether PG&E's gas and electric divisions should be split into separate companies. Each of the aforementioned issues affects MCE as a provider of retail electricity service to customers within PG&E's service territory. Moreover, the issues affect MCE and its customers as recipients of transmission and distribution services from PG&E. The discussions and decisions made in this proceeding will directly impact MCE's interests including the services MCE provides to its customers, the safe provision of transmission and distribution services to MCE's customers, what MCE's customers pay for and receive from PG&E, and the role of CCAs in changing electricity markets. As such, MCE requests party status to participate in, and inform, the discussions of PG&E's potential operational changes, the safe provision of utility service, and what additional roles and responsibilities CCAs may fulfill in the event of material operational changes to PG&E's organization.

Granting MCE's request for party status will not prejudice any party or delay this proceeding because the instant phase has recently commenced with Opening Comments due on January 30, 2019. As such, MCE requests the Commission grant this Motion for Party Status.

SERVICE LIST

If granted party status in the above-captioned proceeding, MCE respectfully requests that the following person be added to the official service list as a party and that service of all notices, orders, and any and all other correspondence in this proceeding be sent via email only:

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CONCLUSION

Based on the foregoing, MCE respectfully requests that the Commission grant its Motion for Party Status.

Respectfully submitted,

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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)

REPLY COMMENTS OF EAST BAY COMMUNITY ENERGY, MARIN CLEAN ENERGY, MONTEREY BAY COMMUNITY POWER, PENINSULA CLEAN ENERGY AUTHORITY, PIONEER COMMUNITY ENERGY, CITY OF SAN JOSE, SILICON VALLEY CLEAN ENERGY, SONOMA CLEAN POWER, AND VALLEY CLEAN ENERGY ALLIANCE

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For Monterey Bay Community Power

February 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)

REPLY COMMENTS OF EAST BAY COMMUNITY ENERGY, MARIN CLEAN ENERGY, MONTEREY BAY COMMUNITY POWER, PENINSULA CLEAN ENERGY AUTHORITY, PIONEER COMMUNITY ENERGY, CITY OF SAN JOSE, SILICON VALLEY CLEAN ENERGY, SONOMA CLEAN POWER, AND VALLEY CLEAN ENERGY ALLIANCE

Pursuant to the Assigned Commissioner's Scoping Memo and Ruling dated December 21, 2018 and amended January 22, 2019[1] (the "ACR"), East Bay Community Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy Authority, Pioneer Community Energy, the City of San José on behalf of San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy Alliance (collectively, the "Joint CCAs") respectfully submit the following comments. Marin Clean Energy and Monterey Bay Community Power submitted separate opening comments but join in this reply.[2]

The Joint CCAs are all Community Choice Aggregators ("CCAs") based in Northern California and serving PG&E's customers. The Joint CCAs consist of not-for-profit public agencies operating either as joint power authorities or, in the case of San José Clean Energy, as

1 Pursuant to the Presiding Officer's January 22, 2019, E-MAIL Ruling Granting Extension of Time, these comments are timely filed.

2 Silicon Valley Clean Energy and the City of San José submitted separate opening comments as well but also joined the Joint CCA opening comments.

part of the municipal government.[3] The Joint CCAs appreciate the opportunity to respond to parties' opening comments regarding Pacific Gas & Electric's ("PG&E") safety culture and future.

I. SUMMARY OF JOINT CCA REPLY COMMENTS

The common thread across party opening comments is that the status quo is untenable. Even PG&E admits it has not lived up to its responsibility to "design, build, maintain, and operate its energy systems to keep customers and communities safe."[4] Party comments, including PG&E's own, show that the question before the Commission is what, not whether, massive structural changes to PG&E's businesses are in order. PG&E itself is inviting exploration of reorganization on a scale that would have been inconceivable just a year ago. The Joint CCAs acknowledge that many of the issues being addressed in this phase of the proceeding are beyond what can feasibly be resolved through a single round of comments and replies at a single state agency. Yet, there is unprecedented potential in this proceeding to engage these issues and move towards resolution that can facilitate a safer, cost-effective, reliable, and decarbonized energy system in California.

The Joint CCAs are uniquely situated to promote safer electricity service in California. To that end, the Joint CCAs put forward several proposals in their opening comments for a safer California electricity system:

- Remove PG&E from the retail and generation businesses, thereby allowing PG&E (or its successor) to concentrate on the safe operation of its electric transmission and distribution systems.

3 San José Clean Energy is the City of San José's CCA program, which is administered by the San José Community Energy Department.
4 PG&E Opening Comments, page 1.

- Put programs such as demand response, energy efficiency and transportation electrification under local control, again to allow the “wires” company to focus on safe operation.

- Facilitate community control of retail generation services through a variety of local governance models.

In these reply comments, the Joint CCAs respond to parties’ opening comments on select issues, as follows:

- Separating PG&E’s electric and gas businesses warrants further discussion in this proceeding so that parties and the Commission can fully understand what steps would be necessary to complete such a separation and the associated pros and cons.

- Removing PG&E from the retail and generation businesses and concentrating PG&E’s attention and investments on its electric transmission and distribution businesses is supported by numerous parties and should be a focus of this proceeding going forward.

- Managing PG&E’s distribution system as a transparent, neutral, open-access platform can improve safety outcomes and better facilitate the achievement of State policy goals.

- Facilitating increased community control of retail and generation services is broadly supported by opening comments and an important part of improving PG&E’s safety outcomes.

- The Commission should focus on overseeing PG&E’s divestment of its current energy portfolio of utility-owned generation and third-party contracts to the extent practicable.

II. JOINT CCA RESPONSES TO PARTIES’ OPENING COMMENTS

With this reply, the Joint CCAs identify issues that would benefit from further exploration in this proceeding, as well as issues that will need to be resolved in other venues. However, given PG&E’s size, safety failures, and bankruptcy filing, the State government is going to have to coordinate across multiple levels to ensure Northern Californians receive safe, reliable, cost-effective, and decarbonized electricity service consistent with State and local policy goals.

A. Separating PG&E's electric and gas businesses warrants further consideration.

PG&E invites consideration of separating its electric and gas businesses. Without formally taking a position on whether that is ultimately advisable, PG&E identifies several potential benefits from such a separation. Most importantly, PG&E states: "The separation of PG&E's gas operations from its electric operations has the potential to reduce the total risks managed by a single entity."[5] According to PG&E, "[t]his could increase operational focus by each entity and improve the development of each entity's safety management system."[6] PG&E also opines that stand-alone gas and electric entities "likely would be of sufficient scale to continue to respond to emergencies and would have sufficient expertise in the compliance and risk management functions."[7] Marin Clean Energy reaches a similar conclusion: "a complete separation of PG&E into independently operated gas and electric entities would be a fundamental first step towards improving PG&E's operational scale and scope in order for PG&E to better focus on safe, reliable and economic provision of utility service to customers."[8]

The Joint CCAs believe the pros and cons of a gas/electric split warrant further consideration. The Commission and parties should also fully explore the steps necessary to complete such a separation. PG&E notes that separating its gas and electric operations "could increase rates".[9] However, PG&E does not provide an assessment of the potential rate increases. Although PG&E suggests that one-time and ongoing costs may be able to be mitigated, the

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5 PG&E Opening Comments, page 20.
6 *Id.*
7 *Id.*, page 21.
8 Marin Clean Energy ("MCE") Opening Comments, pages 4-5.
9 PG&E Opening Comments, page 21.

mechanism PG&E proposes for doing so would require separate, regulated electric and gas businesses to be constituted under a single, unregulated holding company.[10]

The Joint CCAs do not take a position on PG&E's hypothesized structure for separating its electric and gas businesses under a single, non-regulated holding company, although the Joint CCAs agree with TURN that the "the Commission needs to have the resources to *ensure compliance* with the standards its sets for PG&E's performance, which will require far greater oversight over PG&E's operations going forward."[11]

In sum, separating PG&E's gas and electric businesses would benefit from further discussion in this proceeding, with a focus on: the costs and benefits of the various options for separating PG&E's electric and gas businesses, what corporate structure lends itself to a necessary level of Commission oversight, and the associated safety benefits of each alternative.

B. Numerous parties support focusing PG&E's attention and investments on its electric transmission and distribution businesses. This outcome should be a focus of this proceeding going forward.

PG&E is currently responsible for managing a variety of unique risks associated with its electricity business, including risks associated with power generation, electric transmission, distribution infrastructure, and retail energy supply. According to PG&E's opening comments, "the potential benefit of a wires-only company would be that, by reducing the total number of risks managed by PG&E, it could lead to better management of the remaining risks."[12]

Numerous parties, including Marin Clean Energy and Monterey Bay Clean Power, who both join in this reply, support focusing PG&E's attention and investments on its transmission and distribution businesses as a means to improve the safety of these systems. According to

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[10] *Id.*, pages 21-22.
[11] TURN Opening Comments, page 26 (*italics* in original).
[12] PG&E Opening Comments, page 34.

Marin Clean Energy, a wires-only company could "focus specifically on the risks and needs of the electric grid and make the necessary investments to address these needs and risks."[13] Monterey Bay Clean Power agrees: "It is undeniable that, by removing peripheral distractions, like provision of generation services, PG&E will be more focused on operating and maintaining its delivery system in a manner that enhances safety, and avoids or significantly mitigates the destructive impact of safety errors."[14] Shell Energy North America proposes that "[t]he Commission should begin immediately to take the steps necessary to direct PG&E to separate its gas and electric procurement from its gas and electric transmission/distribution operations."[15]

The Joint CCAs agree that removing PG&E from the retail and generation businesses and concentrating PG&E's attention and investments on its electric transmission and distribution businesses is critical to improving PG&E's safety outcomes, and therefore should be a focus of this proceeding. Given PG&E's status as a decoupled utility that receives the majority of its energy from third-party generators, transitioning PG&E out of providing retail service will facilitate an increased emphasis on safety management, with limited impacts to PG&E's workforce or financial stability. To achieve this outcome, the Commission should accelerate the already ongoing migration of PG&E's bundled retail customers to one or more CCAs. In addition to the Joint CCAs, the City and County of San Francisco and South San Joaquin Irrigation District also support transitioning some or all of PG&E's retail sales activities to one or more public entities.[16]

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13 MCE Opening Comments, page 9.
14 Monterey Bay Community Power Opening Comments, page 4.
15 Shell Energy North America Opening Comments, page 5.
16 CCSF Opening Comments page 2; South San Juaquin Irrigation District ("SSJID") Opening Comments, page 1.

Under the Joint CCA proposal, where a CCA is in place, the CCA could become the principal energy provider for customers within the CCA footprint. For customers not within a CCA's footprint, a new or existing public agency could be responsible for procuring energy and capacity on their behalf. This entity would be explicitly directed to support communities in joining existing, or forming new, CCAs. Provision could be made for phasing this entity out as locally based CCAs are established. While the public agency is being developed, PG&E should continue to provide transitional generation services to customers not served by a CCA.

C. The Joint CCAs support other parties' proposals to operate PG&E's distribution assets as a transparent, neutral and open-access platform.

Several parties propose that PG&E's distribution system should be operated as a transparent, neutral, open-access platform, similar to its transmission system, with the goal of supporting the deployment of distributed energy resources, transportation and building electrification, and other demand-side management strategies that further California's climate goals. For example, the Center for Climate Protection proposes that the Commission reform PG&E's distribution function "to align its operations, business model and incentives with state policy goals for decarbonization and resilience, and to enable all residents in PG&E's service area to realize maximum benefits from the proliferation of distributed energy resources ("DER"), a phenomenon that is occurring not only in California but worldwide."[17] It proposes that the distribution system should be operated "to be an effective collaborator with local governments and their relevant agencies to develop and implement electrification and resilience-related energy projects that address community needs in alignment with power system benefits."[18] Marin Clean Energy supports these goals and states that "[t]his coordination is especially crucial as wildfire

[17] Center for Climate Protection Opening Comments, pages 5-6.
[18] *Id.*, page 8.

risks increase as a result of climate change and non-IOU load-serving entities ("LSEs") and other service providers take on more substantial roles in the energy sector."[19]

Marin Clean Energy specifically proposes that PG&E's distribution system should:

- Become "plug and play" to address generation in its myriad forms, including DERs, storage and other applications;
- Provide effective data, metering and billing operations, including the ability to provide real-time data access; and
- Provide transparent load and distribution level data in order to ensure all entities are investing appropriately in a safe and reliable grid and generation supply.[20]

Silicon Valley Clean Energy's opening comments emphasize the role that enhanced overall transparency has to play in upholding public safety: "Transparency enhances our ability to catch potential problems before they materialize, especially in a system changing as rapidly as California's is."[21] The Joint CCAs agree with parties' opening comments proposing to more effectively manage PG&E's distribution system and encourage the Commission to further explore these proposals in this proceeding.

D. Parties broadly support providing communities the opportunity and authority to proactively pursue full community control of retail and generation services, as an important part of improving PG&E's safety outcomes.

Numerous parties submitted opening comments supporting an expansion of public agencies as a means to improve safety while ensuring that all customers continue to have access to safe, reliable, clean, cost-effective energy. In addition to the Joint CCAs' opening comments, these parties include American Public Power Association,[22] City and County of San Francisco,[23]

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19 MCE Opening Comments, page 12.
20 MCE Opening Comments, page 11.
21 Silicon Valley Clean Energy ("SVCE") Opening Comments, pages 8-9.
22 American Public Power Association ("APPA") Opening Comments, page 1 (although American Public Power Association takes no position regarding what specific actions the Commission should take, APPA highlights the significant safety, reliability, and other benefits of publicly owned electric utilities).

the City of San José on behalf of San José Clean Energy,[24] EMF Safety Network,[25] Marin Clean Energy,[26] Monterey Bay Community Power,[27] Silicon Valley Clean Energy,[28] and South San Joaquin Irrigation District[29].

Given the weight of these comments, CCAs and municipal utilities should be viewed as an essential part of the solution to improving the safety of PG&E's operations.[30] Local agencies have a long history of providing reliable, cost-effective electricity in their communities. CCAs, which currently serve the vast majority of retail customers in their communities, are uniquely positioned to move quickly to serve the remaining bundled customers within their communities. As previously discussed, to assist PG&E's orderly exit from retail service, CCAs should be empowered to absorb PG&E's bundled customers and serve as the provider-of-last-resort within the CCAs' service territories. This addresses the question PG&E raised in opening comments as to who will take over its responsibilities as provider-of-last-resort. The Joint CCAs acknowledge that this outcome will require statutory amendments and regulatory clarification of the specific obligations of a provider-of-last-resort. However, prioritizing such discussions and amendments will provide the clarity necessary to facilitate PG&E's transition out of retail and generation services and expedite PG&E's refocus on the safety of its transmission and distribution businesses. This clarity will ensure that all customers continue to have access to safe, reliable, clean, affordable energy. It will also support CCAs in their efforts to invest in new renewable

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23 CCSF Opening Comments, pages 2, 13-16.
24 City of San José Opening Comments, page 3.
25 EMF Safety Network Opening Comments, page 2 (EMF takes the position that "[i]f PG&E is divided up, every city and county in PG&E's service territory should be given the chance to become their own publicly owned utility").
26 MCE Opening Comments, page 8.
27 Monterey Bay Community Power Opening Comments, pages 1-6.
28 SVCE Opening Comments, pages 1-2.
29 SSJID Opening Comments, pages 1-10.
30 San José states in its opening comments that it "strongly supports the Joint CCAs' request that the Commission eliminate barriers for communities that desire to pursue full municipalization." Page 4.

development, transportation electrification, and other projects that advance California's climate goals.

E. The Commission should focus on overseeing PG&E's divestment of its current energy portfolio of utility-owned generation and third-party contracts to the extent practicable.

PG&E raises the question of how to divest its generation assets if it is no longer in the retail sales business. PG&E states:

> Implementing [the proposal for PG&E to be a 'wires-only company'] would pose several challenges and take considerable time to implement. For example, certain generation assets of PG&E, such as the [Diablo Canyon Power Plant] and its decommissioning trust, may not be salable. PG&E also owns the Humboldt Bay Generating Station, which is a reliability asset that is effectively bundled with transmission assets. Additionally, since becoming a "wires only" company would require that PG&E no longer have an obligation to provide energy supply as the provider of last resort, it would need to be relieved of all going-forward procurement responsibilities, and transition its existing contracts.[31]

The Joint CCAs agree that, as a "wires-only" electric utility, PG&E will need to divest its current energy portfolio of utility-owned generation and third-party contracts. To accomplish this, the Commission should engage in an orderly process to facilitate PG&E divestiture of these resources, possibly in coordination with State, regional, and local agencies that wish to acquire such resources. For resources for which divestment is impractical, the Commission should direct PG&E to auction or otherwise resell the energy, capacity, environmental, and other resource attributes in a manner which maximizes resource value (possibly in Phase 2 of the Power Charge Indifference Adjustment ("PCIA") docket, R.17-06-026, where portfolio optimization is under discussion pursuant to D.18-10-019). For resources which are divested or resold below cost, PG&E should recover stranded costs through a transitional charge which applies to all

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[31] PG&E Opening Comments, page 35.

customers. Again, this may be best addressed in the PCIA docket, R.17-06-026, where stranded cost recovery is already being addressed.

The Joint CCAs appreciate that divestiture may be complicated by a number of factors, including that: (i) the entities that may be interested in stepping into PG&E's shoes as the buyers under these contracts do not know the terms of these contracts, given existing Commission confidentiality rules; and (ii) these contracts are currently the subject of both the Federal Energy Regulatory Commission and federal bankruptcy court proceedings.

Although the Commission's options to resolve these issues may raise significant legal complexities, the Joint CCAs believe these issues are worth grappling with in order to remove PG&E from the retail and generation businesses and concentrate PG&E's attention and investments on its electric transmission and distribution businesses. However, given the limitations noted above, the Joint CCAs do not believe PG&E's wholesale contracts should be a focus of this proceeding.

III. CONCLUSION

The Joint CCAs appreciate the opportunity to respond to parties' opening comments and look forward to working with the Commission and parties in this proceeding to identify the best path forward for providing Northern California with safe and reliable electric and gas service at just and reasonable rates, in light of PG&E's safety failures and recent bankruptcy filing.

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Investigation 15-08-019
(Filed August 27, 2015)

OPENING COMMENTS OF MARIN CLEAN ENERGY ON THE ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

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February 13, 2019

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**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)

**OPENING COMMENTS OF MARIN CLEAN ENERGY
ON THE ASSIGNED COMMISSIONER'S
SCOPING MEMO AND RULING**

Pursuant to the directions set forth in the *Assigned Commissioner's Scoping Memo and Ruling* ("Scoping Memo") issued on December 21, 2018, Marin Clean Energy ("MCE") respectfully submits the following comments on the Scoping Memo. On January 9, 2019, The Utility Reform Network ("TURN") moved to extend the due date of these comments to February 13, 2019. The TURN motion was granted by Administrative Law Judge Peter Allen on January 15, 2019. Pursuant to Rule 11.6 of the California Public Utilities Commission ("Commission" or "CPUC"), these comments are timely filed. MCE filed a motion for party status in this proceeding, which was granted via e-mail ruling on February 8, 2019.

I. INTRODUCTION

A. MCE Seeks Strategic Reforms to PG&E to Prioritize Safety, Decarbonization, Modernization and Equity

MCE's priority in this proceeding is to ensure that any restructuring of Pacific Gas and Electric Company ("PG&E")[1] prioritizes safety, facilitates the state's decarbonization goals,

[1] References to PG&E in these Comments may also refer to any successor or "spin-off" of PG&E.

creates a more modern "plug and play" grid and protects the state's most vulnerable communities. The current PG&E bankruptcy is an inflection point in the California energy industry and the Commission should use this opportunity to make structural improvements to PG&E, or any successor entity, to better position it to truly serve the public and achieve these objectives.

In these comments, MCE recommends:

- Separating PG&E's gas and electric lines of business 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.

B. Procedural Posture and Current Developments

Since the issuance of the Scoping Memo, there have been significant developments related to PG&E. On January 13, 2019, PG&E and PG&E Corporation (the "Corporation" and together, "PG&E") announced in a United States Securities and Exchange Commission Form 8-K filing that PG&E expected the Corporation and the Utility "will file for reorganization under Chapter 11 in the U.S. Bankruptcy Court for the Northern District of California on or about January 29, 2019."[2] Subsequently, on January 29, 2019, PG&E filed for bankruptcy.[3]

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[2] https://www.sec.gov/Archives/edgar/data/75488/000095015719000032/form8k.htm.
[3] In re PG&E Corp., Case No. 19-30088 (Bankr. N.D. Cal. 2019) and *In re* Pac. Gas & Elec. Co., Case No. 19-30089 (Bankr. N.D. Cal. 2019).

C. The Impact of This Proceeding on MCE

This proceeding and the significant changes expected to result from the PG&E bankruptcy process drive to the core of MCE's mission to reduce greenhouse gas ("GHG") emissions and MCE's long-standing commitment to equity. Notably, the Legislature created CCA in the wake of PG&E's last bankruptcy as an alternative model for retail electricity generation services run by local government on behalf of communities. MCE is California's first operational 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.

MCE's core mission is to address climate change by reducing energy-related GHG emissions. MCE effectuates this mission by securing clean energy supply, maximizing price stability, providing energy efficiencies and promoting local and economic workforce developments that directly benefit MCE's member communities and which also have positive ramifications for the state as a whole. For example, MCE has contracted for over 800 megawatts (MW) with new California renewable energy projects, including approximately 480 MW in the Central Valley.

Deeply embedded in MCE's activities is empowerment of customers who may not otherwise have access to renewable energy options and technologies, enabling these customers to invest in a carbon-free future at an affordable price. MCE's activities in this area come in the form of an expansive suite of energy efficiency offerings, including MCE's Low Income Families and Tenants ("LIFT") pilot that serves hard-to-reach low-income customers and identifies barriers to participation in low-income energy efficiency programs. MCE also offers low-income rebates on solar panels in partnership with GRID Alternatives and is launching low-income rebates towards the purchase of electric vehicles ("EVs"). Through these efforts, MCE is empowering all of its customers to take control of their energy usage and reduce their carbon footprint. The Commission should support the work MCE and other CCAs are doing throughout the state to advance equity and accelerate the state's energy policies by exceeding state requirements.

II. CORPORATE GOVERNANCE – BOARD OF DIRECTORS

MCE has no comment on the specific proposed structures related to the governance of PG&E's Board of Directors.

III. CORPORATE MANAGEMENT – OFFICERS AND SENIOR LEADERSHIP

MCE has no comment on the specific proposed structures related to the corporate management of officers and senior leadership.

IV. CORPORATE STRUCTURE

A. Separation of Gas and Electric Distribution and Transmission Divisions

Questions: Should PG&E's gas and electric distribution and transmission divisions be separated into separate companies? If so, should the separate companies be controlled by a holding company? Should the holding company be a regulated utility?

1. Safety First: Separation of electric and gas entities will allow for improved focus on safety matters

This proceeding's primary focus should be to ensure customers receive the safe utility service they deserve. Although not the only step needed, a complete separation of PG&E into independently operated gas and electric entities would be a fundamental first step towards improving PG&E's operational scale and scope in order for PG&E to better focus on safe, reliable and economic provision of utility service to customers.

PG&E fundamentally needs a change in corporate culture to prioritize the safety of ratepayers. A mere "on paper" change to corporate structure will not on its own create the necessary change. A corresponding change to corporate culture is needed to allow more transparency and accountability. Without a corresponding change in corporate culture, the corporate restructuring would only further insulate PG&E from liability without providing ratepayers with the safe provision of electric and gas services they deserve.

2. *Separation of the PG&E gas and electric businesses would support the state's decarbonization goals*

Separating the PG&E gas and electric services into separately operated entities would also support California's ambitious environmental policies. MCE shares California's goal to reduce the use of carbon emitting resources – natural gas included – and replace those resources with non-emitting resources.

As the Commission contemplates a potential split of PG&E into separate gas and electric entities, the ultimate outcome should culminate in the safe and incremental transition away from reliance on natural gas and other GHG-emitting resources in the electricity, gas and broader energy sectors. The Commission should set policies to create opportunities to further divest from gas-based technologies and its infrastructure and modernize the grid so that the needs of customers and grid reliability can be met with GHG-free generation resources or distributed generation resources ("DERs").

MCE is committed to decarbonization and supports structuring the energy sector to focus on decarbonization efforts. By definition, this means reducing natural gas use and actively supporting fuel switching from natural gas or other carbon-emitting sources to electricity produced by renewable and/or GHG-free resources. Having a single-purpose, wires-only electricity provider and a separate single-purposed, gas provider would support this decarbonization and fuel-switching focus as discussed in more detail below.[4]

B. Separation of Corporate Structure by Region

> ***Questions:*** Should PG&E's corporate structure be reorganized with regional subsidiaries based on regional distinctions? For example, PG&E could be divided into multiple smaller utilities operating under a single parent company. If so, should such a reorganization apply to both gas and electric services? Do the physical characteristics of the gas and electric systems lend themselves to the same regional structure, or do the physical characteristics of the respective systems lend themselves to different regional structures?

MCE does not support a separation of corporate structure by region. MCE does not perceive any safety benefit to dividing PG&E into multiple smaller utilities where those separate utilities simply feed up to the same parent or holding company. Such a structure would create more regulatory complexities and result only in risk mitigation for PG&E without any additional protections for ratepayers or operational benefit in the energy industry.

1. Separation of PG&E into regional entities raises equity concerns

If the Commission were to consider any regional disaggregation of the utility, the Commission must prioritize equity issues. Ratepayers in the various regions will likely face significant impacts to rates because the cost of service differs in each area. The Commission should prevent any undue or dramatic rate impacts on the State's most vulnerable customers, including California Alternate Rates for Energy ("CARE") and Medical Baseline customers and those living in disadvantaged communities throughout PG&E's service territory.

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[4] Fuel switching can run the gamut from electrification of vehicles, to replacing a gas dryer with an electric heat pump dryer, to the large building electrification efforts envisioned in Senate Bill ("SB") 1477 (2018). As technologies continue to improve, even efficient gas appliances should and will be replaced with cleaner electric technologies.

In the event of any form of PG&E restructuring, it is critical for the Commission to support universal equity programs and facilitate and support supplemental programs that may be funded through individual Load Serving Entities' ("LSE") generation revenues. The Commission must take all steps necessary to ensure the State's most vulnerable communities are not disproportionately disrupted by a PG&E restructuring.

2. *Separation of PG&E into regional entities would fail to improve the technical or operational functioning of PG&E*

Furthermore, splitting PG&E into smaller regional entities would likely add difficulties to the technical or operational functioning of PG&E, particularly in its role as the exclusive billing and metering agent for CCAs. Regional subsidiaries may create further technological and functional barriers that complicate billing and access to metering data and may stifle the growth of DERs. If the Commission were to consider creating regional subsidiaries, the Commission should specifically evaluate impacts on billing mechanics, ratemaking and energy efficiency program operations. The Commission must take steps to ensure that creation of such subsidiaries does not lead to unnecessary complexities that create undue cost increases for ratepayers.

C. Revocation of Holding Company Authorization

Questions: Should the Commission revoke holding company authorization, so PG&E is exclusively a regulated utility? Should all affiliates and subsidiaries be spun off or incorporated into the regulated utility?

MCE has no comment on these questions.

D. Safety Working Group with Union Leadership

Question: Should the Commission form a standing working group with the union leadership of PG&E to identify the safety concerns of PG&E staff?

MCE has no comment on this question.

V. PUBLICLY OWNED UTILITY, COOPERATIVE, COMMUNITY CHOICE AGGREGATION OR OTHER MODELS

A. Reconstitution of Utility as Publicly Owned Utility or Utilities

Question: Should some or all of PG&E be reconstituted as a publicly owned utility or utilities?

MCE takes no position on complete municipalization of PG&E. MCE would expect the existing choices of the communities that have chosen CCA to be respected and upheld according to law. MCE also would expect that the choice of any individual community (or group of communities) that would seek to municipalize would also have their decision respected and facilitated by the Commission to the fullest extent supported by law.

The Commission should empower local governments to continue to make decisions that best serve the needs of their communities and support local communities that choose to expand their responsibilities and programmatic offerings within their jurisdictions, be it in the form of expansion of service obligations or transitions towards municipalization.

B. Transformation of PG&E to a "Wires-only Company"

Questions: Should PG&E be a "wires-only company" that only provides electric distribution and transmission services with other entities providing generation services? If so, what entities should provide generation services?

MCE supports PG&E transitioning to a wires-only company. MCE believes the potential to provide safer utility service to Northern Californians is the primary benefit of a wires-only PG&E. A secondary benefit of transitioning PG&E to a wires-only company is to take steps to ensure that its grid is modernized to enable greater decarbonization, DERs and customer choice efforts.

1. PG&E should be a wires-only company in order to improve safety

In order to create a clear focus on safety, MCE recommends restructuring PG&E such that one resulting entity is a wires-only company. This would allow the entity to focus specifically on the risks and needs of the electric grid and make the necessary investments to address these needs and risks. Essential to this wires-only company should be improved transparency of PG&E's fire safety policies and implementation efforts, particularly as they pertain to PG&E's operation and maintenance of its electric distribution infrastructure.

To this end, MCE solicited feedback from its communities' first responders and local safety personnel to gather additional local perspectives about what safety measures should be prioritized and implemented under any restructuring. First and foremost, our first responders recommended that transparency take the form of improved communication and coordination with first responders and local communities. As an example, PG&E should be directed to improve its reporting and dissemination of information related to fire safety efforts by creating a public and transparent database documenting and detailing PG&E's maintenance records and progress towards its safety goals. This will help local fire officials better understand where the greatest risks lie in the areas they serve. This increased transparency will assist local officials in optimizing safety resources by directing mitigation and improvement efforts to where they are most needed.

There should also be improved coordination and partnerships with local government entities, in particular local fire departments, to prevent and mitigate the effects of wildfires and other safety issues related to utility equipment. Some key strategies that local fire departments, safety and emergency personnel have recommended include:

- Creating a generation notification process to the local jurisdiction when intensive fuel reduction work occurs in a community;

- Pausing certain types of electric or gas infrastructure maintenance work on days when fire risks are high;
- Providing fire suppression on work sites to help extinguish a fire;
- Creating reporting requirements for any emergencies, including fires;
- Improving protocols to mitigate impacts of public safety de-energization events, which would include a single, consistent and updated notification matrix for public safety and local officials in the event of a Public Safety Power Shutoff;
- Ensuring utility distribution infrastructure maps and tracking documents are updated to accurately reflect the current distribution system conditions, particularly in the event of a de-energization situation (*i.e.* reflect changes to distribution line pathways, undergrounding projects, etc.);
- Improving coordination with local and regional government entities, in particular local fire departments, in order to: (1) ensure there is comprehensive understanding of where local high-risk areas are and whether these risks are due to vegetation or equipment issues and (2) facilitate timely and coordinated mitigation efforts to prevent and respond to wildfires;
- Improving partnerships and consultation with local communities to inform residents of the safety importance of PG&E's activities such de-energization of utility lines and vegetation management, while also acknowledging the impacts of de-energization on local communities and residents; and

- Requiring PG&E to perform a cost analysis for under-grounding utility lines in high-risk areas.[5]

The Commission should take steps to ensure that PG&E, in whatever form it ultimately takes, internalizes the foregoing in its operations, implements safety measures consistently and thoroughly, and that PG&E's resulting corporate and management structure be sufficiently nimble to efficiently address additional safety improvements raised by local communities and stakeholders.

2. The wires-only company should also focus on decarbonization and modernization of the grid

In addition to safety, decarbonization and modernization of the grid should be key priorities of the wires-only company. Specifically, PG&E must improve its operations to:

- Become "plug and play" to address generation in its myriad forms, including CCA, distributed generation, storage and other applications;
- Provide effective data, metering and billing operations, including the ability to provide real-time data access; and
- Provide transparent load and distribution level data in order to ensure all entities are investing appropriately in a safe and reliable grid and generation supply.

These are functions naturally served by a transmission and distribution utility. The transition of PG&E out of retail generation solely to ownership, operation and maintenance of the transmission and distribution systems would provide a unique opportunity for LSEs to establish

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[5] The improved reporting requirements mentioned above could inform this analysis and help focus under-grounding efforts and investment in other infrastructure improvements on the most problematic areas most likely to be affected by critical weather conditions or infrastructure malfunctions.

new partnerships with utility. However, even if the Commission ultimately decides not to transition PG&E out of its generation business, the data sharing and transparency issues should be addressed and resolved such that the distribution utility be required to provide LSEs with timely distribution-level data to be used to develop local demand side programs that can shift demand, reduce demand, reduce GHG-emissions and reduce costs for ratepayers by off-setting costly distribution system upgrades. Such data sharing and transparency is not available at present.

As California moves to increased customer choice and CCAs and other generation service providers take on increased responsibility, it is essential for LSEs to have improved communication with and insight into the distribution grid to optimally and strategically serve their loads, reduce GHG emissions and obviate costly distribution grid upgrades. This coordination is especially crucial as wildfire risks increase as a result of climate change and non-IOU LSEs and other service providers take on more substantial roles in the energy sector. These LSEs and other service providers will need more accurate, timely data to conduct load forecast and resource scheduling during emergencies or de-energization.

3. Where PG&E is a wires-only electricity provider, CCAs represent a key solution to providing generation service

CCAs have been a stabilizing force in the market, particularly for new renewable resources that are crucial for decarbonizing the electricity grid. Where PG&E is now facing bankruptcy, the CCAs, their customers and their many renewable and resource adequacy providers have viable, ongoing business relationships. Furthermore, CCAs have been strong advocates for a clean energy future. California and the Commission have set forth a vision of the future to decrease GHG emissions, increase renewables and increase innovation. CCAs have exceeded the high standards set by the State and the Commission and have been an important partner in supporting their vision and in creating this energy future.

The Commission's role in this future wires-only structure would be essential to ensure appropriate and safe wires management, appropriate modernizations to the grid and improved transparency, particularly as it relates to metering and data access. The Commission should ensure that the modernized PG&E grid is "plug and play," where CCAs are able to access our customers' data to develop programs that further reduce electricity sector GHG emissions.

a. Where a CCA seeks to serve as the principal retail generation service provider in its service area, the Commission should support that community decision.

Some CCAs may wish to be the principal retail service provider in their service area (*i.e.* providing all retail energy generation services to all customers within a CCA's service area). The Commission should support such community decisions. Current Direct Access customers should not be impacted by this transition and should still be able to retain their service from an Energy Service Provider ("ESP"). In the case where a CCA would serve as principal retail service provider, cost and competitive pressures would still continue from other providers, including ESPs and behind the meter generation and technologies.

b. Where a community seeks to serve as a CCA, the Commission should support that community decision.

For communities not currently served by a CCA, MCE recommends streamlining current CPUC processes that create up to a two-year wait to form or join a CCA.[6] Specifically, the Commission should reduce the time between when a community files a new or amended implementation plan with the CPUC and the launch of the CCA from current 12 months to 6 months or fewer. These changes would benefit communities not currently served by CCAs by facilitating their ability to form a new CCA or join an existing CCA.

[6] Resolution E-4907.

4. CCAs are not the sole solution where PG&E is a wires-only company – a stakeholder process must start now to achieve a safe, decarbonized and equitable future of electricity generation service

CCAs are not the sole solution in an electricity structure where PG&E serves as a wires-only company. In the case of divesting PG&E of its generation role, new or enhanced generation structures will need to be considered. This will require a thoughtful stakeholder process to determine an appropriate generation structure and also to set a process for achieving that structure.

The Scoping Memo sets forth various key considerations in framing stakeholder process, including safety and reliability, decarbonization and the cost of utility service.[7] MCE recommends including equity in these considerations in order to give a voice to the most vulnerable in our communities, including but not limited to low-income customers, customers in disadvantaged communities and customers in areas most susceptible to wildfires.

This stakeholder process should also address several thorny issues, including: procurement autonomy of each LSE, reliability standards and resources beyond resource adequacy, SB 1136 (directing the Commission to determine clean resource adequacy requirements for LSEs) and treatment of stranded assets. This will require robust communication and collaboration among all entities engaging with California's electricity industry, including across California's regulatory bodies (the Commission, the California Energy Commission, the California Air Resources Board and the California Independent System Operator) and the Legislature.

VI. <u>RETURN ON EQUITY</u>

MCE has no comment on this section.

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[7] Scoping Memo at 12-13.

VII. OTHER PROPOSALS

MCE has no comment on this section.

VIII. CONCLUSION

MCE thanks Assigned Commissioner Michael Picker and Assigned Administrative Law Judge Peter V. Allen for the opportunity to provide these comments on the Scoping Memo.

Respectfully submitted,

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February 13, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 18-07-003 (Filed July 23, 2018)

COMMENTS OF THE JOINT CCA PARTIES ON PROPOSED DECISION ACCEPTING DRAFT 2018 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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Dated: February 11, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	))))))	Rulemaking 18-07-003 (Filed July 23, 2018)

COMMENTS OF THE JOINT CCA PARTIES ON PROPOSED DECISION ACCEPTING DRAFT 2018 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the CCA Parties respectfully submit these comments on the *Proposed Decision Accepting Draft 2018 Renewables Portfolio Standard Procurement Plans* ("PD"), issued on January 22, 2019.[1]

I. COMMENTS ON THE PD

The PD accepts the Draft 2018 Renewables Portfolio Standard ("RPS") Procurement Plans filed by the CCA Parties and states the Community Choice Aggregators ("CCAs") submitted RPS Procurement Plans that "provided the information required in Sections 5.1-5.6 and 5.8, and 5.11-5.13 of the 2018 [Assigned Commissioner Ruling ("ACR")]."[2] The CCA Parties appreciate the PD's confirmation that the CCAs' plans demonstrate adherence with

[1] Pursuant to Rule 1.8(d), Apple Valley Choice Energy, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority have authorized the undersigned counsel to sign and file these comments on their behalf.

[2] PD at 101.

mandated requirements. The procurement of RPS-eligible energy is a central part of the mission of CCAs.

While acknowledging adherence to the requirements for RPS Procurement Plans, the PD expressed concern about the level of detail included in CCA plans:

> As several parties noted, many of the CCAs' 2018 RPS Procurement Plans were scant on information. The RPS plans mandated by Pub. Util. Code § 399.13(a)(1) must be more than a list of factors to consider during procurement. They must explain how the LSE plans to reach its Net RPS Procurement Need. Specifically, in the RNS Calculations LSEs submit to the Commission, CCAs should address whether they will hold a solicitation this year, how many MWs they intend to procure this year, how many MWs they intend to procure long term, the resources they intend to procure in particular portfolio content categories, their Net RPS Procurement Need (variable E in the RNS calculation table), the steps planned to reach it, what appropriate minimum margin of procurement and information on upcoming participation in solicitations or other forms of procurement that are needed.[3]

The PD implies that many CCAs have simply provided a "list of factors to consider during procurement." A review of the filed CCA Procurement Plans demonstrates that these plans go beyond a mere list and generally provide the specific information identified in the paragraph above. For example, all of the 2018 RPS Procurement Plans submitted by each of the CCA Parties includes an attached Renewable Net Short Calculation Table that provides the individual CCA's Net RPS Procurement Need through 2030. Similarly, all of the CCA Parties have described their approach to a minimum margin of over-procurement in Section 5.6 of their RPS Procurement Plans and most have identified a specific amount of voluntary over-procurement in Variable D of the Renewable Net Short Calculation Table.

While the degree of detail varies across the CCAs, this is primarily due to the fact that many of the CCAs have only recently begun providing service to customers. Newly-formed

[3] *Id.* at 102 (internal citations omitted).

CCAs often secure short-term arrangements to meet energy supply needs during early-stage operations and then transition to the development of owned resources and the execution of long-term contracts. Consequently, not all CCAs will be able to precisely identify all planned long-term procurement during their initial years of operation.

The CCA Parties also ask that the Commission be mindful of the existing reporting burdens on Retail Sellers and work to eliminate unnecessary or duplicative reporting requirements. Any requested information should be necessary to demonstrate a compliance requirement, or alternatively, providing this information must serve a clear public policy purpose. The Commission's role in the RPS procurement decisions of CCAs is fundamentally different than its role for the investor owned utilities ("IOUs"). Because the Commission does not approve the contracts of CCAs or oversee their RPS procurement solicitations, the Commission necessarily needs far less information regarding these CCA activities. However, this does not mean that this information is not publicly available. As public agencies, the procurement and solicitation activities of the CCAs are carried out in a transparent and open process, subject to the oversight and approval of their own local governing boards. In future submittals, the CCA Parties will endeavor to identify website locations and other sources of information on these processes.

Further, the Commission should also ensure that any requested information is not readily available in some other mandatory filing. For example, CCAs also provide information regarding future RPS procurement in their RPS Compliance Reports, Integrated Resource Plans, and in their Implementation Plans. If any of the identified data in the PD is already available in one of these other filings, the Commission should not demand that it be included in the Procurement Plans as well, or alternatively, the Commission could work to streamline or otherwise combine these reports. Likewise, the CCA Parties will work collaboratively as part of future submittals to identify where in other filings, RPS-related data and information is located. By avoiding duplicative reporting, the Commission can reduce the administrative burdens and costs of compliance with the RPS.[4]

The CCA Parties look forward to working with the Commission in advance of the filing of the 2019 RPS Procurement Plans to ensure that the reporting requirements are clearly understood. The CCA Parties are mindful of the Commission's desire for more information on long-term procurement planning efforts, and will seek to address each of the individually identified items listed in the PD, where applicable. To more accurately reflect the content of the CCAs' 2018 RPS Procurement Plans, the CCA Parties recommend that the following changes be made to page 102 of the PD (with strikeouts showing removal and underline showing additions):

> ~~As several parties noted, many of the CCAs' 2018 RPS Procurement Plans were scant on information.~~ The RPS plans mandated by Pub. Util. Code § 399.13(a)(1) must ~~be more than a list of factors to consider during procurement. They must~~ explain how the LSE plans to reach its Net RPS Procurement Need. Specifically, in the RNS Calculations LSEs submit to the Commission, CCAs should address whether they will hold a solicitation this year, how many MWs they intend to procure this year, how many MWs they intend to procure long term, the resources they intend to procure in particular portfolio content categories, their Net RPS Procurement Need (variable E in the RNS calculation table), the steps planned to reach it, what appropriate minimum margin of procurement and information on upcoming participation in solicitations or other forms of procurement that are needed.

[4] The CCA Parties briefly make note of a regulatory issue that the CCA Parties have tried in several proceedings to examine and address – an issue that exploits the IOUs' inherent market power advantages. (*See* Senate Bill 790 (2011); Sec. 2.) Specifically, the IOUs are able to recoup their regulatory advocacy and compliance costs from ***all*** customers, including CCA customers, through distribution charges. CCAs, on the other hand, are only able to recoup regulatory costs through generation charges, which are borne only by CCA customers. The CCA Parties renew their request that the Commission be mindful of this competitive imbalance and work in other proceedings to correct the imbalance.

II. CONCLUSION

The CCA Parties appreciate the opportunity to provide these comments on the PD.

February 11, 2019,

Respectfully submitted,

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

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 18-07-003 (Filed July 23, 2018)

REPLY COMMENTS OF THE JOINT CCA PARTIES ON PROPOSED DECISION ACCEPTING DRAFT 2018 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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(collectively, "CCA Parties")

Dated: February 19, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	))))))	Rulemaking 18-07-003 (Filed July 23, 2018)

REPLY COMMENTS OF THE JOINT CCA PARTIES ON PROPOSED DECISION ACCEPTING DRAFT 2018 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the CCA Parties respectfully submit these reply comments on the *Proposed Decision Accepting Draft 2018 Renewables Portfolio Standard Procurement Plans* ("PD"), issued on January 22, 2019.[1] In these reply comments, the Joint CCA Parties respond to the opening comments filed jointly by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company ("Joint IOU Comments")[2] and the opening comments filed jointly by the California Wind Energy Association and Large-scale Solar Association ("CalWEA/LSA Comments").[3]

I. REPLY COMMENTS

A. The RPS Procurement Plans Submitted by the CCA Parties Were Not Deficient and the PD is Correct to Accept Them.

The Joint IOU Comments assert that the PD "inappropriately" accepts the Renewables Portfolio Standard ("RPS") Procurement Plans filed by the community choice aggregators ("CCAs") because these plans: (1) did not include additional cost information requested in

[1] Pursuant to Rule 1.8(d), Apple Valley Choice Energy, Clean Power Alliance of Southern California, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, Sonoma Clean Power Authority, and Valley Clean Energy Alliance have authorized the undersigned counsel to sign and file these comments on their behalf.
[2] *Opening Comments of Joint Investor-Owned Utilities on Proposed Decision Accepting Draft 2018 Renewables Portfolio Standard Procurement Plans*, February 11, 2019.
[3] *Comments of the California Wind Energy Association and Large-Scale Solar Association on Proposed Decision Accepting Draft 2018 Renewables Portfolio Standard Procurement Plans*, February 11, 2019.

Section 5.10; and (2) "did not provide sufficient detail on how they planned to reach their Net RPS Procurement Need."[4] These arguments are without merit and should be disregarded.

First, the "cost information" referenced in the Joint IOU Comments was not a mandatory reporting requirement. The *Assigned Commissioner's Corrected Ruling of the Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2018 Renewables Portfolio Standard Procurement Plans Dated June 21, 2018* ("ACR"), issued on July 10, 2018, ***requested*** that CCAs voluntarily provide certain cost quantification data because this information would be "useful" and would "assist the Commission in meeting its system planning and Integrated Resource Planning obligations."[5] Because the cost quantification data was not mandatory, the lack of this information cannot be the basis for rejecting an RPS Procurement Plan.

The Joint CCA Parties also note that many CCAs did plan to submit this information to Commission Energy Division Staff, however, some of the requested information was considered confidential by the CCAs. Several CCAs jointly filed a motion seeking guidance from the Commission on the ability of a CCA to submit parts of this cost quantification data under seal.[6] The Commission has not yet acted on this motion. CCAs have been responsive to other requests, while protecting confidential information. For example, when Energy Division staff authorized CCAs to submit confidential data under seal pursuant to Decision ("D.") 18-10-019, CCAs submitted confidential RPS-related data in accordance with Energy Division staff direction.

Second, the 2018 RPS Procurement Plans submitted by the CCAs fully provided the mandatory information specified in Sections 5.1-5.6 and 5.8, and 5.11-5.13 of the ACR, including information relating to Net RPS Procurement Need. However, the PD, for the first time, identifies additional information that CCAs should provide, primarily relating to CCA solicitations. As stated in the ACR, the Commission has already determined that "it was reasonable to not require the CCAs and ESPs to file solicitation documentation and cost quantification tables in their RPS Procurement Plans."[7] As stated above, the ACR requested this

[4] Joint IOU Comments at 2-3.
[5] ACR at 6 ("This Ruling also **requests** that the CCAs and ESPs include additional cost information in their Plans, similar to that included by the IOUs, as described in Section 5.10. Reporting this information will provide the Commission, the Legislature, and the public with a more complete picture of the state's RPS program." (emphasis added)).
[6] *Motion of CCA Parties to Submit Requested Information Under Seal*, July 9, 2018.
[7] ACR at 6.

information because it would help the Commission with certain planning activities unrelated to RPS compliance.[8] Therefore, this solicitation information cannot be considered mandatory for the CCAs' 2018 RPS Procurement Plans.

However, as stated in opening comments, the Joint CCA Parties will seek to provide the additional information listed in the PD in their 2019 RPS Procurement Plans. In order to help facilitate the submission of this data, the Commission should: (1) provide further guidance on the ability of a CCA to file certain RPS data under seal; (2) provide more clarity on the data it seeks in the 2019 Assigned Commission Ruling; and (3) coordinate and streamline the filing requirements in this proceeding with the filings required in the Integrated Resource Planning proceeding.

B. Contrary to the Assertions Contained in the CalWEA/LSA Comments, the CCAs are Well-Positioned to Meet the Long-Term Procurement Requirements Applicable as of Compliance Period Four.

The CalWEA/LSA Comments assert that CCAs "have not contracted for resources to meet their near-term or long-term RPS requirements" and that their analysis of CCA procurement activities should "raise alarm bells."[9] The CalWEA/LSA Comments reach an incorrect conclusion based on incomplete and outdated information, and therefore, should be disregarded by the Commission. As described in detail below, the 2019 RPS Procurement Plans will show an increase in long-term procurement. This increase will demonstrate that the CCAs are on track to meet both near and long-term RPS requirements.

As stated in the Joint CCA Parties opening comments, the primary reason why many CCAs did not show long-term RPS procurement in their 2018 RPS Procurement Plans was that many are newly formed organizations.[10] It would not be prudent or practical for any load serving entity ("LSE") to immediately procure all of its long-term RPS needs upon its formation. Rushing into the market and procuring all at once would severely limit an LSE's ability to negotiate cost-competitive procurement agreements. Instead, CCAs are utilizing a thoughtful, deliberate, and carefully-planned process that is overseen by their own governing boards.

Of the 20 CCA programs identified in the CalWEA/LSA Comments, only five had provided service to any retail customers by the end of 2016, and only four more CCAs began operations in 2017. Nine of the CCA programs (nearly half of all CCAs in existence) began

[8] *Id.*
[9] CalWEA/LSA Comments at 4.
[10] *See, e.g.,* Joint CCA Parties Comments at 2-3.

operations in 2018, many just months before the 2018 RPS Procurement Plans were filed with the Commission. Two of the CCAs identified in the CalWEA/LSA Comments had not even launched by the end of 2018. For a CCA that formed in 2018, there was insufficient time to execute long-term contracts and to have those long-term contracts reflected in the 2018 RPS Procurement Plans.

For example, Valley Clean Energy Alliance ("VCEA") just launched in June of 2018. It quickly thereafter issued its first Request for Offers for RPS-eligible resources on August 13, 2018. Bids were due September 17, 2018. VCEA is in the process of reviewing bids and fully expects to meet its long-term contracting requirements in time for the compliance deadline of the end of the fourth Compliance Period.[11] VCEA was not, however, able to show such long-term contracts in its 2018 RPS Procurement Plan filed on August 20, 2018, given the timing of its launch and commencement of operations.

Similarly, the California Choice Energy Authority ("CalChoice") issued a Request for Proposals ("RFP") for long-term RPS-eligible procurement on December 10, 2018, with a response deadline of January 9, 2019. The CalChoice members are currently evaluating the responses to the RFP and plan to have contracts executed by April of this year.[12] The responses to the CalChoice RFP were very strong and far exceed what is necessary for CalChoice members to meet their long-term procurement requirements.

Beyond these two examples, there has been substantial solicitation and procurement activity by CCAs since the 2018 RPS Procurement Plans were filed. The CCAs are well aware of the long-term procurement requirements that will become effective as of the fourth Compliance Period and are taking the necessary actions to meet these requirements. CCAs should not be penalized for the timing of their launch and operations, particularly when their RPS Procurement Plans comply with the currently applicable statutory requirements. The PD correctly approves these plans and suggests the need for additional detail *when it is practical for such CCAs to provide it.*

Additionally, the table provided in the CalWEA/LSA Comments appears to overstate the additional capacity necessary for CCAs to meet their long-term RPS procurement requirements. First, the table includes information for two CCAs that had not launched as of 2018. This

[11] *See* Cal. Pub. Util. Code § 399.13(b).
[12] CalChoice member CCAs currently include the cities of Lancaster, Pico Rivera, San Jacinto and Rancho Mirage, and the town of Apple Valley.

accounts for over 10 percent of the alleged shortfall. Second, the table relies on each CCA's voluntary renewable targets rather than the procurement requirements mandated by the RPS program. The 65 percent long-term procurement requirement mandated by Public Utilities Code section 399.13(b) only applies to the statutorily mandated RPS procurement requirements. This accounts for over 13 percent of the alleged shortfall. Third, the table includes assumptions regarding capacity factors and expected delivery that do not align with the current contracts that have been executed by the CCAs. For example, nearly 30 percent of Sonoma Clean Power's contracted RPS capacity is delivered by geothermal resources with a 100 percent capacity factor. Finally, the information in the table is outdated and excludes hundreds of MWs of new procurement. While the CCA Parties welcome further discussion of their procurement activities, there is no immediate crisis as presented by the CalWEA/LSA Comments.

II. CONCLUSION

The CCA Parties appreciate the opportunity to provide these reply comments on the PD. For the reasons set forth herein, the PD correctly accepted the CCAs' 2018 RPS Procurement Plans and this aspect of the PD should not be revised.

February 19, 2019

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	))))))	Rulemaking 18-07-003 (Filed July 23, 2018)

COMMENTS OF THE JOINT CCA PARTIES ON ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENT ON IMPLEMENTATION OF ELEMENTS OF SENATE BILL 100 RELATING TO PROCUREMENT UNDER THE CALIFORNIA RENEWABLES PORTFOLIO STANDARD

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And on behalf of Apple Valley Choice Energy, Clean Power Alliance of Southern California, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority (collectively, "CCA Parties")

Dated: February 28, 2019

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

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	))))))	Rulemaking 18-07-003 (Filed July 23, 2018)

COMMENTS OF THE JOINT CCA PARTIES ON ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENT ON IMPLEMENTATION OF ELEMENTS OF SENATE BILL 100 RELATING TO PROCUREMENT UNDER THE CALIFORNIA RENEWABLES PORTFOLIO STANDARD

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the CCA Parties respectfully submit these comments on the *Administrative Law Judge's Ruling Requesting Comment on Implementation of Elements of Senate Bill 100 Relating to Procurement Under the California Renewables Portfolio Standard* ("ALJ Ruling"), issued on February 11, 2019.[1]

I. RESPONSE TO ALJ RULING

A. The Commission Should Continue to Use a Straight-Line Trend Methodology for Determining the Procurement Quantity Requirements for the Fourth, Fifth, and Sixth Compliance Periods.

Senate Bill ("SB") 2 (1X) (stats. 2011, 1st Ex. Sess.) directed the Commission to establish procurement quantity requirements for the second and third compliance periods that "reflect reasonable progress in each of the intervening years sufficient to ensure that the procurement of electricity products from eligible renewable energy resources achieves 25 percent of retail sales

[1] Pursuant to Rule 1.8(d), Apple Valley Choice Energy, Clean Power Alliance of Southern California, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority have authorized the undersigned counsel to sign and file these comments on their behalf.

by December 31, 2016, and 33 percent of retail sales by December 31, 2020."[2] In Decision ("D.") 11-12-020, the Commission determined that a "straight-line trend provides the most sensible approach to setting quantitative targets that represent retail sellers' 'reasonable progress' for the 'intervening years' of a compliance period."[3] As clarified in D.11-12-020, the individual targets for intervening years are combined to determine the procurement quantity requirement for the entire compliance period,[4] and that there is no requirement to demonstrate a specific procurement amount in any individual year.[5]

In 2015, SB 350 (stats. 2015) established a 50 percent renewable procurement target to be achieved over the course of three new compliance periods, spanning 2021 to 2030. In creating these new compliance periods and setting interim procurement targets, the Legislature did not amend the core statutory language regarding "reasonable progress."[6] Instead, the Legislature simply added new procurement targets to the existing language, as shown below in strikeout and underline:

> For the following compliance periods, the quantities shall reflect reasonable progress in each of the intervening years sufficient to ensure that the procurement of electricity products from eligible renewable energy resources achieves 25 percent of retail sales by December 31, 2016, ~~and~~ 33 percent ~~of retail sales~~ by December 31, 2020<u>, 40 percent by December 31, 2024, 45 percent by December 31, 2027, and 50 percent by December 31, 2030</u>.[7]

When the Commission established procurement quantity requirements for the fourth, fifth, and sixth compliance periods, the Commission noted that SB 350 did "not change the language about intervening year targets that was used in SB 2 (1X) and implemented in D.11-12-

[2] SB 2 (1X), Stats.2011, 1st Ex. Sess., ch. 1 (S.B.2), § 20, eff. Dec. 10, 2011.
[3] D.11-12-020 at 14.
[4] *Id.* at 16.
[5] *Id.* at 16-17.
[6] SB 350, Stats.2015, ch. 547, § 20, eff. Jan. 1, 2016.
[7] *Id.*

020."[8] The Commission then concluded that there was "no reason to revisit the Commission's analysis in D.11-12-020 in order to implement SB 350's analogous requirements."[9]

SB 100 (stats. 2018) increased the 2030 renewable procurement target to 60 percent, and proportionally increased the 2024 and 2027 targets.[10] In increasing these targets, the Legislature again did not amend the "reasonable progress" language and instead only changed the numerical targets.[11] Just as the Commission concluded in D.16-12-040, there is no need to revisit the analysis of D.11-12-020 because no change was made to the relevant statutory language. Therefore, the Commission should continue to use the straight-line trend methodology for establishing the increased procurement quantity requirements for the fourth, fifth, and sixth compliance periods.

This approach is also consistent with the rules of statutory construction. As stated in *Horn v. Swoap*, "[t]he Legislature is presumed to be aware of a long-standing administrative practice . . . . If the Legislature . . . makes no substantial modifications to the act, there is a strong indication that the administrative practice was consistent with the legislative intent."[12] The Commission's implementation of this provision has been in place for over seven years and on two occasions the Legislature has chosen not to amend the relevant language. This suggests that the Legislature supports the current methodology as being consistent with the legislative intent.

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[8] D.16-12-040 at 8.
[9] *Id.*
[10] SB 100, Stats.2018, ch. 312, § 3, eff. Jan. 1, 2019.
[11] *Id.*
[12] *Horn v. Swoap*, 41 Cal. App. 3d 375, 382 (1974); *see also Bd. of Trustees of California State Univ. v. Pub. Employment Relations Bd.*, 155 Cal. App. 4th 866, 877–78 (2007) ("When the Legislature is aware of prior practice, but fails to change it in a later statutory enactment, courts infer not that the enactment expresses legislative disapproval, but rather that it expresses legislative acquiescence – an acknowledgment that the practice is consistent with legislative intent.").

B. The Commission Should Continue to Use the Methodology Adopted in D.16-12-040 for Establishing Procurement Quantity Requirements for Compliance Periods Occurring After 2030.

Unlike the requirements described in the prior section, the methodology for establishing post-2030 compliance period procurement quantity requirements is clear and straightforward. SB 350 prescribed that the procurement quantity requirement for all post-2030 compliance periods would be 50 percent.[13] As the Commission noted in D.16-12-030, because the procurement quantity requirement "does not escalate from one post-2030 compliance period to the next, there is no need for any measure of reasonable progress within a compliance period."[14] Therefore, the procurement quantity requirement is simply an average of 50 percent of retail sales over the three-year compliance period.[15]

The only amendment that SB 100 makes to this provision is to increase the numerical target from 50 percent to 60 percent.[16] Because the relevant statutory language is unchanged, there is no basis for modifying the methodology that the Commission uses to establish these targets. Therefore, the Commission should continue to the use the methodology adopted in D.16-12-040 for establishing the post-2030 compliance period procurement quantity requirements.

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[13] SB 350, Stats.2015, ch. 547, § 20, eff. Jan. 1, 2016.
[14] D.16-12-040 at 10-11.
[15] *Id.* at 11.
[16] SB 100, Stats.2018, ch. 312, § 3, eff. Jan. 1, 2019.

II. CONCLUSION

The CCA Parties appreciate the opportunity to provide these comments on the ALJ Ruling.

February 28, 2019,

Respectfully submitted,

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

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	Rulemaking 18-12-006 (Filed December 13, 2018)

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	)))))	Rulemaking 18-12-006 (Filed December 13, 2018)

OPENING COMMENTS OF THE
JOINT COMMUNITY CHOICE AGGREGATORS

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), and the email ruling of assigned Administrative Law Judge ("ALJ") Doherty, dated January 29, 2019, the Joint Community Choice Aggregators ("Joint CCAs") submit these opening comments on the *Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification* ("OIR"), issued on December 19, 2018.[1]

I. INTRODUCTION

The Joint CCAs commend the Commission for instituting this proceeding to continue and expand upon "the Commission's historical work to support clean transportation…."[2] Much has changed since the Commission first started this work in 2009, including the emergence and recent prevalence of Community Choice Aggregation ("CCA") programs. CCA programs are strong supporters of transportation electrification ("TE") efforts and are accelerating progress towards achieving California's goals.

As further discussed herein, Community Choice Aggregators are essential partners in TE efforts because of their strategic partnerships with city and county governments, bringing local

[1] The Joint CCAs consist of Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), California Choice Energy Authority ("CalChoice"), Silicon Valley Clean Energy ("SVCE") and Peninsula Clean Energy ("PCE").

[2] OIR at 2.

knowledge, expertise, and support to encourage and incentivize fuel-switching. The Joint CCAs urge the Commission through this rulemaking to recognize and encourage the important role CCA programs can play to increase TE deployment as local, not-for-profit electricity generation providers. Giving CCA programs a more prominent role in ratepayer-funded TE efforts will allow the Commission to leverage the organic connections CCA programs have to their local communities and government agencies. Furthermore, active involvement by CCA programs will expand TE growth that may not have otherwise occurred absent an energized and engaged local focus. The Joint CCAs envision this involvement as a complementary element to the investor-owned utilities' ("IOUs") efforts. The Joint CCAs have been encouraged by the Commission's recent authorization of funding for similar complementary efforts provided by Community Choice Aggregators, and the Joint CCAs look forward to advancing a similar type of funding construct in this proceeding.

The Joint CCAs are already operating a number of unique and innovative TE programs in their respective communities. The following is a brief description of these efforts.

A. MCE

MCE was the first CCA program to provide electricity service in California. It began serving retail generation customers in 2010, and currently serves over 470,000 customer accounts. MCE's purpose is to address climate change by reducing energy related greenhouse gas ("GHG") emissions and securing energy supply, price stability, energy efficiency and local economic and workforce benefits.[3] Facilitating the adoption and usage of Electric Vehicles ("EVs"), and also promoting TE more broadly, fits squarely within MCE's mission statement.

MCE's governing board is comprised of elected officials from each of the communities participating in the CCA program. Many of these elected officials also serve on boards for local

[3] *See* http://www.mcecleanenergy.org/about-us/.

urban planning, transit, and transportation planning agencies. As a result of successful multiagency collaboration, Marin Transit recently acquired two all-electric buses for a pilot program.[4] MCE also administers the MCEv Charging program, a rebate program which offers up to 100% on hardware and installation costs for EV charging stations.[5] MCE's EV Charging Program covers both large and small charging stations (from 2 to 20+ charging ports), so properties of any size can benefit.[6] This program allows customers to choose who pays for the electricity by either charging for usage or offering free usage as a benefit to employees or tenants.[7] Additionally, MCE offers both flat EV rates as well as rates that vary based on the time of day when a car is charged, with incentives for charging during off-peak usage hours, such as at night when charging is least expensive.[8]

B. SCP

SCP is the second CCA program in California, and is currently serving about 226,000 customer accounts. The reduction of GHG emissions in Sonoma County is set forth in SCP's joint powers agreement as one of the primary reasons for SCP's formation. SCP sees TE as absolutely critical to California's GHG reduction efforts and has already taken significant steps to encourage TE. For example, SCP has a program called Drive EverGreen, which has already deployed over 1200 EVs through its incentive programs over the past three years. SCP offers customers up-front incentives, though the majority of savings – which average over $10,000 per vehicle – come from dealer cost reductions in exchange for SCP's targeted marketing. SCP also offers heavily-discounted EV chargers to customers, of which over 1,700 have been deployed.

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4 *See* https://marintransit.org/projects/two-battery-electric-buses .

5 *See* https://www.mcecleanenergy.org/wp-content/uploads/2018/08/EVSE-overview-flyer_FINAL.pdf .

6 *Id.*

7 *Id.*

8 *See* https://www.mcecleanenergy.org/ev-charging/ .

The program also provides incentives for customers to purchase Level 2 EV chargers that are "grid-enabled." SCP hopes that its EV-charger incentives will facilitate the development of a "grid enabled" EV charging infrastructure that can help balance grid supply and demand and potentially use EV charging as a load "sink" for midday solar power production.

C. CalChoice and LCE

CalChoice is a California joint powers authority initially formed by the cities of Lancaster and San Jacinto, with expanding membership available to other cities interested in implementing CCA programs using services provided by CalChoice. Lancaster's CCA program, Lancaster Choice Energy ("LCE"), has already made significant progress with TE and EV efforts and programs. For example, LCE is actively involved with the Antelope Valley Transit Authority ("AVTA"), which is currently converting its diesel buses to a 100 percent battery electric bus fleet. AVTA will complete the conversion of its fleet of 75 buses to all-electric by the end of June to become the first zero-emission fleet in North America.[9] LCE incentivized this transition to an all-electric bus fleet by offering a special EV rate to AVTA. Furthermore, Build Your Dreams, ("BYD"), the world's largest manufacturer of EV buses, located its electric bus manufacturing facility in Lancaster in 2013. Lancaster currently owns and operates twenty-nine EV charging stations and ten of these stations provide free charging for public use. Lancaster is investigating how these stations may be used as part of important demand response programs to be operated by LCE. To further advance EV charging efforts, Lancaster collaborated with ebee Smart Technologies to deploy an innovative street light EV charging pilot project in Lancaster.

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[9] *See* https://www.thefourth-revolution.com/buses/small-bus-fleet-first-in-north-america-to-go-all-electric/ .

D. PCE

PCE is the fifth CCA program formed in California. PCE commenced service in October 2016 and currently supplies electricity to approximately 300,000 customers. PCE is committed to serving all of its customers clean affordable electricity with the goal of its energy supply being 100% GHG-free by 2021 and sourced from 100% RPS-eligible resources by 2025. However, the majority of GHG-emissions within San Mateo County (PCE's service territory) come from transportation and natural gas use within the built environment. Thus, PCE is already developing programs to directly reduce emissions from these sources. On the TE front, PCE is offering a suite of programs:

- EV Charging Infrastructure Incentive Program – On December 20, 2018, PCE's Board of Directors approved a $16 million program to accelerate EV charging infrastructure deployment in workplaces, apartments and condominiums, and retail locations. PCE's staff is currently developing the program and anticipates it will rollout this summer. The goal of this four-year program is to meet the TE targets outlined by former Governor Jerry Brown in Executive Order B-16-12 by 2025.[10] To that end, this program will support the deployment of approximately 3,500 chargers across San Mateo County.

- Drive Forward Plus Program – PCE is also developing a plug-in hybrid electric vehicle ("PHEV") program for low- and moderate-income San Mateo County residents in partnership with Peninsula Family Services which operates the Drive Forward Program. PCE anticipates that the program will provide a $4,000 incentive to support the purchase of a used PHEV. The program will align with the state's Clean Vehicle Assistance Program when it restarts in the second or third quarter of 2019. At that time, the incentive is intended to be applied through a loan interest buy-down, loan prepayment or cost of charging reduction.

- Easy Charge Apartments Program – PCE offers a technical assistance program to owners of multi-unit buildings to help them navigate the numerous programs that are available. The program includes free site assessments, guidance on apartment polices and linkage to existing programs supporting deployment of EV chargers.

- 2018 Ride and Drive Campaign – During 2018, PCE offered "Ride and Drives" at a mix of open community and corporate events that generated over 1,000 EV experiences. PCE developed this program because research showed that consumer

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[10] *See* Executive Order B-16-12, which called for 1.5 million zero-emission vehicles ("ZEVs") on California roads by 2025; *see also* Executive Order B-48-18, which calls for 5 million ZEVs by 2030 and the installation of 250,000 EV chargers and 200 hydrogen refueling stations by 2025.

understanding of the opportunity to convert to an EV is very low. Simply put, people will not buy what they do not understand or do not even know exists. This program is designed to address that knowledge gap. PCE anticipates this program will continue in 2019.

- New EV Promotion – During the last quarter of 2018, PCE offered a point-of-sale EV promotion program in partnership with local EV dealerships. By bringing demand to the dealership, PCE was able to secure significant dealer and manufacturer discounts, which combined to an average discount of $5,300 towards the purchase of a new EV. In addition to these dealer/Original Equipment Manufacturer discounts, PCE offered an additional $1,000 rebate. PCE is currently evaluating program results to inform the next phase of this program.

- Community Car Sharing Pilot Program – As part of PCE's Community Pilots Program, PCE is developing a community carsharing pilot program with Envoy Technologies wherein Envoy will deploy three EVs at an apartment community in one of PCE's disadvantaged communities. The pilot is designed to evaluate the community vehicle concept as part of Envoy's larger efforts across the country.

E. SVCE

SVCE was formed in March 2016 and officially launched in April 2017 as the sixth operational CCA program in California. SVCE serves about 268,000 customers in 12 municipalities and Santa Clara County with clean power. SVCE has delivered on its promise to supply carbon-free electricity at competitive rates. Clean electricity from SVCE's carbon-free sources has contributed to a dramatic 21% reduction in area-wide carbon emissions from 2015 levels. In December 2018, SVCE's Board adopted a Decarbonization Strategy and Programs Roadmap ("Roadmap") that sets ambitious goals to further reduce energy-related GHG emissions from 2015 baseline levels to 30% by 2021, 40% by 2025 and 50% by 2030. The Roadmap provides detailed initiatives to help local communities, businesses and individuals further reduce carbon emissions, including from transportation. In addition to offering EV rates to its customers, SVCE anticipates Board approval of its mobility programs in mid-February. These include $8 million in committed funds for EV infrastructure incentives, and approximately $3 million in additional funds to support education and outreach, innovation, grid integration, and new construction EV reach code development to spur TE market transformation.

II. COMMENTS ON THE OIR

As local governmental agencies that engage in close collaboration with other local agencies, Community Choice Aggregators are uniquely poised to implement TE programs in their respective service areas and contribute lessons learned to inform future policy and programs to accelerate TE efforts.[11] CCA programs offer an added communication channel to members of the communities they serve and can deliver EV tariffs, customer education, charging services, recruit charging hosts and support infrastructure deployment. Community Choice Aggregators are also well-equipped to offer TE programs that meet unique local needs and that complement, but do not duplicate, the IOUs' TE programs. Accordingly, the Joint CCAs urge the Commission to ensure that the Transportation Electrification Framework ("TEF") envisioned in the OIR gives Community Choice Aggregators the ability to access funds for TE programs that support the overall goals set by the Commission and that rely on Community Choice Aggregators' local expertise and unique advantages. As further described below, models exist through Commission orders for this form of funding – funding that ensures Commission oversight, collaboration with the IOUs, and equitable treatment for contributions made by Community Choice Aggregators.

As noted in the OIR, since the institution of R.13-11-007, the IOUs have proposed more than $2 billion in TE programs, and to date, the Commission has authorized more than $1 billion in spending.[12] As the Commission is aware, many forecasts indicate that by 2020, the majority

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[11] California's cities were among the first stakeholders to begin planning for and promoting EV adoption. In 2011 the Plug-in Electric Vehicle ("PEV") Collaborative, South Coast Association of Regional Governments ("SCAG"), South Coast Air Quality Management District ("SCAQMD") and other regional government bodies secured $2.2M in state and federal grants to fund community PEV readiness plans throughout California. SCAG and SCAQMD contracted with the Luskin Center at UCLA to prepare plans that provide foundational information and detail the breadth of activities that motivated cities can, and some instances already were undertaking, to remove barriers and actively encourage PEV adoption. These include land-use planning and zoning, parking regulations and enforcement, local building ordinances, permitting and inspections, and public education.

[12] OIR at 7.

of customers in Pacific Gas and Electric Company's ("PG&E") and Southern California Edison's ("SCE") service areas will likely be served by a CCA program.[13] In the context of TE initiatives, the Commission has previously directed the IOUs to consult with Community Choice Aggregators in order to identify ways by which CCA programs could be included in the IOUs' applications.[14] Notwithstanding this encouragement, the IOU applications since the ACR have, as a general matter, failed to meaningfully incorporate CCA programs or their customers.[15]

Nevertheless, as detailed above, the CCA Parties have remained committed to promoting widespread TE deployment in order to reduce GHGs, and the Joint CCAs have developed a number of innovative programs in pursuit of this goal. As the Commission seeks to establish a common and comprehensive framework for evaluating TE investments through its TEF, the Joint CCAs ask the Commission to further empower Community Choice Aggregators to offer their customers efficacious and cost-effective TE programs at scale. The Commission's TEF should leverage Community Choice Aggregators' local expertise, local relationships, and shared motivations to help California meet its TE goals and to ensure that TE efforts equitably meet the needs of all Californians.

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13 *See* PG&E's Application 17-12-011 at 5, footnote 10 ("By 2019, CCA's in PG&E's service territory are projected to be serving over 2 million of the PG&E customers expected to be eligible for default TOU, and only about 600,000 eligible customers would not be served by a CCA. . .); *see also* the Clean Power Alliance Implementation Plan Addendum Number 3 *available at* https://cleanpoweralliance.org/wp-content/uploads/2018/12/CPA-Implementation-Plan-Addendum-3_20181219.pdf .

14 *See, e.g., Assigned Commissioner's Ruling Regarding the Filing of the Transportation Electrification Applications Pursuant to Senate Bill 350*, dated September 14, 2016, in R.13-11-007 ("ACR") at 10 ("We encourage the electric utilities to consult with any CCAs in their territory to both determine how independently-funded CCA TE programs can be leveraged and incorporated into their applications and how utilities can ensure their proposed TE programs will serve CCA customers."). *See also* Decision ("D.")18-12-006*,* dated December 13, 2018, in A. 14-10-014 at 15 ("[W]e look forward to seeing more collaboration efforts amongst SCE and CCAs in the pending Phase 2 application.")

15 *See, e.g., Protest of the California Choice Energy Authority*, in A.18-06-015, dated August 9, 2018, at 4-5.

A. The Commission Should Leverage CCA Programs to Help Achieve California's TE Goals by Allowing Community Choice Aggregators to Access Funding for EV Programs.

The Joint CCAs recommend that the Commission, as a part of the TEF, develop a framework through which CCA programs are able to access funding collected from all ratepayers in order to develop and deploy TE and EV programs with a localized focus. As described earlier, the Joint CCAs are already pursuing a myriad of TE programs in their service territories. Many if not most of the Joint CCAs' programs are tailored to meet unique local needs and leverage the Joint CCAs' local relationships. Community Choice Aggregators are well positioned to understand and target local impediments to EV adoption. By contrast, many of the IOUs' TE programs are, by necessity, designed to meet the needs of broad swathes of customers across their large service territories. Community Choice Aggregators should be empowered to supplement and complement the IOUs' "one-size, fits-all" TE programs with localized TE programs or elements. To do so, Community Choice Aggregators should be permitted to access the same funding sources that the IOUs rely on for their TE programs.

Access to funding is appropriate in this context. Community Choice Aggregators are committed and motivated partners in achieving California's ambitious TE goals. Community Choice Aggregators exist to meet the clean energy goals of the communities that created them and accelerating widespread TE is consistent with those goals. Accordingly, the Joint CCAs encourage the Commission to leverage the Community Choice Aggregators' shared commitment to TE, as well as their local expertise and local relationships, to help achieve California's goals.

As the OIR points out, currently approved IOU TE programs are recovered through distribution rates, which are paid by both bundled and unbundled customers alike.[16] However, to date, Community Choice Aggregators are only able to fund TE programs using revenue collected

[16] *See* OIR at 12.

through their generation rates. More specifically, each of the Joint CCAs' TE programs described earlier are funded by generation rates paid by the respective CCA's customers, not bundled customers, even though the programs provide broad benefits to California and not just to the CCA's customers. Accordingly, CCA customers are currently paying to support CCA TE programs through their generation rates, while also paying distribution rates to support IOU TE programs.

The Joint CCAs are pleased to use some of the proceeds from their generation rates to offer the numerous TE programs described earlier because the programs benefit customers and are consistent with their missions. However, Community Choice Aggregators should be permitted to fund their TE efforts in the same manner and on the same scale as the IOUs. To put it another way, Community Choice Aggregators should not be foreclosed from offering larger TE programs to their customers simply because the Community Choice Aggregators are not distribution utilities. As will be discussed in more detail below, the Joint CCAs understand that the Commission may address and potentially modify the manner in which TE program funding is collected during this proceeding. Regardless of the ultimate funding mechanism chosen, the Commission should ensure that Community Choice Aggregators can access such funding on an equitable basis.

B. Existing Funding Mechanisms Provide Models and Options to Fund Community Choice Aggregators' TE Programs.

As an example of the sort of equitable funding mechanism that the Joint CCAs envision, Community Choice Aggregators can either apply to administer, or elect to administer, energy efficiency funds for their customers. The Commission should consider developing a similar construct with criteria under which a CCA program could access funds earmarked for TE programs. Similarly, in D.18-06-027, the Commission adopted programs to promote solar distributed generation in disadvantaged communities ("DAC Solar Programs") using funds collected from all customers, including CCA customers.

In D.18-06-027, the Commission addressed the issue of whether CCA programs should receive funding opportunities for complementary efforts advanced by CCA programs to develop DAC Solar Programs. In response, the Commission agreed "with CCA parties that the Community Solar Green Tariff program [and DAC-Green Tariff program] should be available to both bundled and unbundled customers."[17] The Commission reasoned "[t]his is both because both groups of customers pay for the program, and (more to the point) because the potential benefits of the program should not be limited based upon the retail energy choice of customers."[18] Thus, D.18-06-027 permits CCA programs to "work with Energy Division and the IOU that provides distribution service to its customers to develop and implement their own Community Solar Green Tariffs. . ."[19] CCA Community Solar Green Tariffs programs will be implemented by a Tier 3 advice letter, which ensures Commission authorization and oversight.[20]

The Commission also recently adopted a resolution that provides further funding and cost-recovery opportunities for Community Choice Aggregators. In Resolution E-4977, the Commission implemented portions of Senate Bill ("SB") 901 (2018) that provide for extensions of certain bioenergy power purchase agreements using feedstock from high hazard zones for wildfire and falling trees. In recognition of the fact that Community Choice Aggregators may serve as counterparties under these extended agreements, the Commission ordered that "[p]rocurement expenses incurred by a community choice aggregator shall be eligible for cost recovery via the methodology adopted in D.12-18-003…" upon adherence with various

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17 D.18-06-027 at 63.

18 *Id.* at 87.

19 *Id.*

20 *Id.*

requirements, including the submittal of a Tier 3 advice letter by the Community Choice Aggregator.[21]

The Joint CCAs are very encouraged by the Commission's recent acknowledgement of the need to equitably fund efforts by Community Choice Aggregators. The Joint CCAs believe that the approaches employed of late for funding, using a Tier 3 advice letter process, could be adapted for the TE space to the benefit of all Californians. The Commission could also consider allowing CCA programs to formally submit applications for funding. This approach would be similar to the approach utilized with energy efficiency program funding. Finally, the Commission could designate a third-party entity to review and award TE funds for specific proposals made by Community Choice Aggregators, similar to how the California Energy Commission ("CEC") presently administers the Electric Program Investment Charge ("EPIC") program.

Utilizing one of these approaches can help ensure that the use of ratepayer funds is maximized in order to achieve the greatest number of benefits in broadly promoting TE efforts and reducing GHG emissions. The Joint CCAs continue to investigate programmatic models to grant Community Choice Aggregators access to these funds based on other California programs—and potentially programs in other states—and look forward to sharing those findings in due course within this proceeding.

C. The Joint CCAs Appreciate the Express Recognition of the TE Cost Allocation Issue.

The Joint CCAs appreciate that the OIR discusses the important issue of cost allocation. Specifically, the OIR notes:

> [C]urrently approved TE programs are largely recovered through the distribution rates of all utility customers, regardless of which customers can participate in the programs and how much of the customer-side

[21] *See* Resolution E-4977 at 37-38; Ordering Paragraph 6.

> infrastructure may be owned and operated by the utilities. As more customers choose to take service from providers other than the incumbent utility (e.g., as customers of Community Choice Aggregators), the Commission should consider how to equitably allocate costs and benefits of clean transportation programs funded by ratepayers.[22]

The Joint CCAs are encouraged by the Commission's willingness to explore resolution of this important issue in this proceeding. The Joint CCAs agree that recovery of all TE program costs through distribution rates may not be the most equitable approach, particularly if Community Choice Aggregators do not have access to funding associated with these TE program costs. In this regard, the Joint CCAs have previously argued that TE efforts are closely associated with goals and costs that are generation-related in nature and, accordingly, some portion of the IOU TE costs ought to be allocated to the generation function.[23] This approach is equitable, and consistent with principles of cost causation. However, the Joint CCAs also recognize that TE also serves a public purpose, and therefore it may be more equitable to use the Public Purpose Program ("PPP") charge, or perhaps another mechanism such as EPIC, to allocate some or all of the TE program costs.[24]

The Joint CCAs look forward to exploring cost allocation issues in depth through the course of this proceeding. The Joint CCAs recognize that there are myriad ways of addressing these cost allocation issues.[25] The Joint CCAs' primary concern is not with the precise

[22] OIR at 12.

[23] *See Opening Brief of MCE, SCP, Lancaster and SVCE on the Priority Review Transportation Electrification Proposals* in A. 17-01-020 et. al., dated June 16, 2017, at 10-14.

[24] The PPP approach was adopted by the Commission with respect to the allocation of costs associated with tree mortality power purchase agreements, including costs incurred by Community Choice Aggregators in support of this directive. (*See* D.18-12-003 at 24; Finding of Fact 10 ["The PPP charge is an appropriate vehicle for collecting the TM NBC through customer rates."]. *See also* Resolution E-4977 at 13.)

[25] Not mentioned yet is the Commission's previous treatment of demand response program costs, which may serve as another approach that could be considered for TE program costs. The Commission described its approach, which the Commission labeled as the "competitive neutrality cost causation principle," as follows: "In order to combat this barrier [namely, double-payments by CCA customers], the Commission adopted the competitive neutrality cost causation principle whereby a competing utility shall

mechanism through which such TE funds are recovered, but with ensuring that Community Choice Aggregators have equitable access to such funds, and that the costs associated with such funds are equitably allocated.

D. CCA Programs Should Be Taken into Account as the Commission Develops a Holistic Policy for Evaluating EV Programs.

The Joint CCAs are committed to promoting widespread TE deployment in order to reduce GHG emissions, and, as described above, the Joint CCAs have already developed a number of innovative programs in pursuit of this goal. As the Commission develops its TEF for evaluating future TE proposals, it should account for the ability of Community Choice Aggregators to develop TE programs that complement, without duplicating, the IOUs' programs.

The Commission has grappled with this issue previously. The *Community Choice Aggregation En Banc Background Paper*, issued by the Commission's Energy Division Staff in preparation for the February 1, 2017 En Banc hearing ("En Banc Paper") highlighted how "there is currently no mechanism to ensure CCA and IOU [TE] programs are complementary rather than duplicative" and that "[a]s a result, there is a risk that CCA customers will pay for EV programs offered by the IOU and also pay for similar programs offered by their CCA."[26] The Joint CCAs agree this issue is important and recommend the Commission's new TEF include a collaborative stakeholder process between Community Choice Aggregators and the IOUs, supervised by the Commission, to ensure that duplication is avoided and that complementary efforts are advanced, to the maximum extent possible.

Other areas of collaboration are necessary, and the Joint CCAs appreciate the efforts made by the IOUs to ensure clarity and a holistic outcome. For example, PG&E clarified and

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cease cost recovery from and targeted marketing to a Community Choice Aggregator or Direct Access provider's customers when that provider implements a similar demand response program in the utility's service territory." (D.17-10-017 at 9 [referencing D.14-12-024; Ordering Paragraph 8.b.].)

26 En Banc Paper at 10.

agreed that the generation supply for any new EV charging station for PG&E's EV/TE programs would be provided by the relevant Community Choice Aggregator if the location owner is a CCA customer.[27]

E. CCA Programs Should Be Given A Greater Opportunity to Serve as Marketing, Education and Outreach ("ME&O") Partners.

Fairly reimbursed CCA programs have the potential to be excellent partners in the ME&O space. This proceeding should consider ways by which CCA programs could access funding in order to market and incentivize EV programs in a manner that complements IOU programs, but also allows for a more localized focus. This would ensure that CCA customers are not paying for ME&O twice (once through generation charges paid to the CCA program and once through distribution charges paid to the respective IOU).[28]

Additionally, the Commission should consider requiring IOUs to adhere to certain requirements when the IOUs are marketing programs that are open to both bundled and unbundled customers. For example, under the Settlement Agreement in PG&E's EV Infrastructure and Education Program (A.15-02-009), PG&E agreed that "[f]or EV charging equipment and service deployment efforts within communities participating in CCA programs, PG&E staff will collaborate and coordinate with the corresponding CCA to further enhance these deployment efforts within these communities. Furthermore, any marketing efforts to promote Charge Smart and Save within such communities will be presented in a manner that highlights the collaborative efforts of PG&E and the resident CCA."[29] This approach ensures that customers receiving generation service from a Community Choice Aggregator are aware that

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27 *See Joint Motion for Adoption of Settlement Agreement*, in A.15-02-009, dated March 21, 2016, at 11-13.

28 *See* En Banc Paper at 10.

29 *See Joint Motion for Adoption of Settlement Agreement*, in A.15-02-009, dated March 21, 2016, at 12 (and approved in part by the Commission in D.16-12-065).

their status as a CCA customer does not prohibit them from accessing IOU program offerings. In the past, IOUs and CCA programs have worked together to create messaging that contains the logos of both the CCA program and the incumbent IOU. This approach should be formalized moving forward. Furthermore, language must remain neutral and be endorsed by both the IOU and the CCA program. Therefore, the Joint CCAs recommend that IOUs be required to partner with CCA programs in development of ME&O materials for TE and EV programs. This approach would also be consistent with that agreed to by PG&E in deployment of its Charge Smart and Save program, as described above.

Finally, the Joint CCAs seek to ensure that any potential competitive bias which may come as a result of the IOUs administering TE programs is sufficiently mitigated. In this regard, the Joint CCAs have the same concern as the Legislature, namely, that the inherent market power advantages held by the IOUs (including name recognition through the administration of public purpose programs), should not be used as a deterrent to the development of CCA programs.[30] The Joint CCAs look forward to working with the IOUs and the Commission to advance ways to appropriately mitigate the IOUs' inherent market power.

III. PARTY STATUS

The Joint CCAs understand that, in accordance with Rule 1.4(a)(2)(ii), the filing of comments on this OIR allows the Joint CCAs party status in this proceeding. The Joint CCAs hereby request that they individually be given party status, with the party of record listed as following for each of the Joint CCAs:

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30 *See, e.g.,* SB 790 (2011); Section 2(c) and (f).

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IV. CONCLUSION

The Joint CCAs thank Assigned Commissioner Picker and ALJs Doherty and Goldberg for their consideration of the matters discussed herein. The Joint CCAs look forward to collaboratively participating in this proceeding in order to ensure that CCA programs are enabled to serve as effective implementation partners in the TE space moving forward. As discussed above, the Joint CCAs already have a demonstrated track record of success with respect to TE, and remain ambitious with their TE goals. Moreover, the key role played by Community Choice Aggregators in facilitating and enhancing local engagement and multiagency collaboration has been proven repeatedly. Thus, Community Choice Aggregators are well suited to be effective partners with the IOUs in the quest to reduce GHG emissions via active TE efforts across California.

Dated: February 11, 2019

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	)))))	Rulemaking 18-12-006 (Filed December 13, 2018)

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS

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

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	)))))	Rulemaking 18-12-006 (Filed December 13, 2018)

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), and the email ruling of assigned Administrative Law Judge ("ALJ") Doherty, dated January 29, 2019, the Joint Community Choice Aggregators ("Joint CCAs") submit these reply comments on the *Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification* ("OIR"), issued on December 19, 2018.[1]

I. REPLY COMMENTS

As local governmental agencies that engage in close collaboration with other public agencies, including regional agencies, Community Choice Aggregators are uniquely poised to facilitate and implement transportation electrification ("TE") programs in their respective service areas, and to contribute lessons learned to inform future policy and programs to accelerate TE efforts. The Joint CCAs offer the following comments in response to certain matters raised by other parties in opening comments.

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1 The Joint CCAs consist of Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), California Choice Energy Authority ("CalChoice"), Silicon Valley Clean Energy ("SVCE"), Peninsula Clean Energy ("PCE") and Monterey Bay Community Power ("MBCP"). Though not yet granted party status, MBCP is concurrently filing a Motion for Party Status in this proceeding today, February 26, 2019.

A. The Commission Should Thoroughly Examine the Interrelated Nature of Rates in This Proceeding.

In opening comments, the Utility Consumers' Action Network ("UCAN") raised a very important issue that should be examined through the course of this proceeding. As more fully described in UCAN's comments, UCAN states that, given the size and structure of the Power Charge Indifference Adjustment ("PCIA"), which is applied to Community Choice Aggregation ("CCA") and direct access customers on a *flat*, per-kWh basis, there is a potential inherent disadvantage to CCA and direct access customers vis-à-vis bundled customers, who are not subject to the same flat, per-kWh structure, but rather pay for PCIA-related costs through generation rates that vary under TE rate structures. UCAN explains this point as follows:

> The OIR also states that the joint proposal should include cost-based [time of use ("TOU")] rates that 'reduce the cost of using off-peak electricity as a transportation fuel well below the cost of conventional fuels such as diesel and petroleum,' consistent with California statute. However, the current rate structures available in California ensure that this will be more challenging for direct access [("DA")] and CCA customers. Because the [PCIA] is structured as a flat $ per kWh charge, with a high PCIA, CCAs and DA suppliers face the prospect of charging very low rates during super off-peak periods that may be well below their cost of service in order to maintain competitiveness with the electric vehicle [("EV")] charging incentives embedded in bundled rates and offer rates consistent with Commission direction with regard to rates for electric vehicles. The Commission should clarify whether the rate design for the PCIA, as an [investor-owned utility ("IOU")] rate, is in scope for the IOU's joint proposal. If it is out of scope, UCAN recommends that the Commission still direct the IOUs to show their joint proposal creates a reasonable opportunity for customers who choose to take service from a competitive supplier and pay the PCIA to access off-peak rates resulting in EV charging costs below conventional fuel costs.[2]

The Joint CCAs agree with UCAN, and are concerned about the impacts that current rate design may have on CCA programs' abilities to compete and offer EV rates which are below conventional fuel costs. As noted above, the issue arises in the context of the PCIA because, for bundled customers, the cost that comprises the PCIA is included in IOU generation rates, which

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[2] UCAN Comments at 3.

are allowed to vary based on time periods. However, for CCA customers, the PCIA is not embedded within generation rates, and therefore is not TOU-based, but rather is applied on a flat, per-kWh basis. This could potentially result in a disincentive for CCA customers to charge during otherwise advantageous time periods, since the layering of a flat, per-kWh onto this time period may distort price signals. In light of the significant number of California customers now served, or expected to be served by a CCA program in the near future, the Joint CCAs request that the Commission examine within the scope of this proceeding the interrelated nature of rates. While the PCIA looms large within this examination, since it is so large, other rates and rate elements also warrant examination. The Joint CCAs also agree with UCAN that, at a minimum, the Joint IOUs' respective proposals should illustrate that there is a "reasonable opportunity for customers who choose to take service from a competitive supplier and pay the PCIA to access off-peak rates resulting in EV charging costs below conventional fuel costs."[3]

Finally, the issue identified by UCAN appears to be similar to an issue proposed for consideration in Pacific Gas and Electric Company's ("PG&E") recent application for approval of a commercial EV rate (A.18-11-003). In the Scoping Memo for that proceeding, the following issues were determined to be within the scope, among others:

4. Are the interactions of PG&E's proposal with Community Choice Aggregators reasonable?
    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?[4]

Issue 4.a., in particular, seems similar to the one raised by UCAN, but the other issues also could be implicated. The Joint CCAs commend the Commission for expressly identifying

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3 *Id.*

4 Scoping Memo (A.18-11-003), dated February 14, 2019, at 3.

in A.18-11-003 rate-related issues, and their associated interaction with and impact on CCA programs, as issues for consideration in that proceeding. The Joint CCAs understand that the TEF developed in the instant proceeding will not impact any outcome in A.18-11-003, since it was filed prior to December 1, 2018. However, as the Commission develops the Transportation Electrification Framework ("TEF") for future use, the Joint CCAs request that the Commission continue to explore these rate related issues to ensure EV rates are designed in a manner that does not result in IOUs possessing a competitive advantage over CCA programs.

B. The Joint CCAs Support Development of a TEF That Retains Flexibility to Ensure CCA Programs Are Incorporated and Accommodated by IOUs.

The Joint CCAs agree with the important theme of retaining flexibility in the TEF that was raised by a number of parties in opening comments. For example, Advanced Energy Economy ("AEE") suggests that "[t]he TEF should not be overly prescriptive in program design but should provide opportunity for utility innovation and utility-specific flexibility."[5] Similarly, the Alliance for Transportation "urges the Commission to define TEF parameters that encourage flexibility for the IOUs to develop a variety of ranges and scenarios."[6] Finally, the Natural Resources Defense Council ("NRDC") is concerned that the OIR's guidance for developing a TEF could inappropriately prescribe program design, and suggests instead that "[t]he proposed 'common' framework should continue to encourage diversity in program design to demonstrate what works and what does not."[7] The Joint CCAs agree with these points, and add that "flexibility" ought to include the potential for inclusion, incorporation and accommodation of CCA TE programs.

[5] AEE Comments at 9.

[6] Alliance For Transportation Comments at 4.

[7] NRDC Comments at 1-2.

As noted in the Joint CCAs' opening comments, "many of the IOUs' TE programs are, by necessity, designed to meet the needs of broad swathes of customers across their large service territories."[8] Alternatively, "Community Choice Aggregators are well-equipped to offer TE programs that meet unique local needs and that complement, but do not duplicate, the IOUs' TE programs."[9] Thus, enabling CCA programs to develop robust TE programs will increase overall diversity of programs and also more thoroughly demonstrate the viability of potential TE solutions. Therefore, in this regard the Joint CCAs reiterate their principal requests from opening comments, namely, that the Commission ensure that the TEF envisioned in the OIR (1) accounts for the ability of Community Choice Aggregators to develop TE programs that complement, without duplicating, the IOUs' programs; and (2) gives Community Choice Aggregators the ability to access funds for development of TE programs.[10]

C. The Joint CCAs Agree with San Diego Gas & Electric Company that Local Efforts Promoting TE Programs are Needed.

In opening comments, San Diego Gas & Electric Company ("SDG&E") noted that "[w]hile a broad marketing effort is helpful to push TE, local efforts in promoting programs available in each service territory and specific markets are also needed."[11] The Joint CCAs agree that although broad general marketing, education, and outreach ("ME&O") is beneficial, the Commission should also, through this proceeding and in the TEF, ensure that there are avenues to enable more specialized and locally/regionally specific ME&O.

As the Joint CCAs noted in opening comments, CCA programs have the potential to be excellent partners in the ME&O space – both with respect to local ME&O and ME&O for

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8 Joint CCA Opening Comments at 10.

9 *Id.* at 8.

10 *Id.*

11 SDG&E Comments at 7.

specific markets.[12] Therefore, the Joint CCAs reiterate their prior suggestion that this proceeding actively facilitate discussion on ways by which CCA programs can be encouraged to participate as ME&O partners, including by considering funding efforts for CCA programs in order to market and incentivize EV programs in a manner that complements IOU programs, but also allows for a more localized focus, which might be best-suited for the area.

II. CONCLUSION

The Joint CCAs thank Assigned Commissioner Rechtschaffen and ALJs Doherty and Goldberg for their consideration of the matters discussed herein. The Joint CCAs look forward to working with the Commission and other stakeholders in this proceeding to find ways to leverage Community Choice Aggregators' shared commitment to TE, as well as their local expertise and local relationships, to help achieve California's goals.

Dated: February 26, 2019

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12 *See* Joint CCAs Opening Comments at 16.

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)

COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON PROPOSED PREFERRED SYSTEM PORTFOLIO AND TRANSMISSION PLANNING PROCESS RECOMMENDATIONS

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BEFORE THE PUBLIC UTILITIES COMMISSION
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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)

COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON PROPOSED PREFERRED SYSTEM PORTFOLIO AND TRANSMISSION PLANNING PROCESS RECOMMENDATIONS

In accordance with the January 11, 2019 *Administrative Law Judge's Ruling Seeking Comments On Proposed Preferred System Portfolio And Transmission Planning Process Recommendations* ("Ruling"), Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCP"), Silicon Valley Clean Energy Authority ("SVCE"), Lancaster Choice Energy ("Lancaster"), Pico Rivera Innovative Municipal Energy ("PRIME"), San Jacinto Power ("SJP"), Rancho Mirage Energy Authority ("RMEA"), Apple Valley Choice Energy ("AVCE"), Peninsula Clean Energy Authority ("PCE"), and Monterey Bay Community Power ("MBCP") (the "Joint Community Choice Aggregators" or "Joint CCAs") respectfully submit the following comments on the Commission's Proposed System Portfolio and Transmission Planning Process ("TPP") recommendations.

I. RESPONSES TO QUESTIONS ON PRODUCTION COST MODELING RESULTS AND THE PREFERRED SYSTEM PORTFOLIO

Question 1:

> *Do you support the staff recommendation that the Commission adopt the hybrid conforming portfolio as the basis for the Preferred System Plan for the 2017-2018 IRP Cycle? Why or why not?*

Response to Question 1:

The Joint CCAs support the staff recommendation that the Commission adopt the Hybrid Conforming Portfolio ("HCP") as the basis for the Preferred System Plan ("PSP") for the 2017-

2018 IRP cycle. Although the HCP's accuracy is hampered by a number of issues, addressing these issues at this late date in the IRP cycle would be inefficient and would risk overlap and inconsistency with the next IRP cycle. The Joint CCAs recognize that this first iteration of the IRP process is, of necessity, a rough "trial run." As long as the flaws identified by CCA programs in these comments and elsewhere in this Rulemaking are adequately remedied in the 2019-2020 IRP cycle, the Joint CCAs believe that the HCP should be adopted as a reasonable first attempt at projecting the load-serving entities' ("LSE") combined portfolio in 2030.

The HCP supports a number of points that CCA programs have raised from the outset of the IRP Rulemaking. First, as CCA programs have repeatedly noted, CCAs are collectively and individually meeting the State's Greenhouse Gas ("GHG") reduction goals. According to RESOLVE, the HCP would reduce GHG emissions in the CAISO footprint to 34 MMT in 2030.[1] Individually, in many cases the conforming portfolios submitted by CCA programs would provide GHG reductions well in excess of those required to meet the programs' respective shares of required emissions reductions.

Second, the HCP demonstrates that CCA programs can be relied upon to drive new renewable resource development and the transition to a statewide renewable energy economy. Over 90% (well over 10,000 MW) of the HCP's proposed new procurement would come from CCA programs, while investor-owned utilities ("IOU") and energy service providers ("ESP") combined account for less than 10% (under 1000 MW) of proposed new procurement.[2] Tellingly, nearly 100% of CCA programs' new resource buildout proposed in the HCP is from renewable resources: over 6,500 MW of new solar (fixed and tracking); nearly 3,000 MW of new wind; and 1,000 MW of new 4-hour battery storage; and a small amount of geothermal.[3]

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1 *Administrative Law Judge's Ruling Seeking Comments On Proposed Preferred System Portfolio And Transmission Planning Process Recommendations* (January 11, 2019), Attachment 2 at Slide 88.
2 *Id.* at Slide 35.
3 *Id*. at Slide 34.

The CCA programs do not propose any new fossil fuel generation or GHG-emitting biogas or biomass resources.[4]

Third, the HCP demonstrates that CCA programs can be relied upon to drive new resource development and achieve the States' GHG reduction goals *based on the local goals set by their governing boards*, and in *collaboration with the Commission*, without the need for the Commission to mandate renewable procurement. The HCP is composed, in significant part, of conforming portfolios voluntarily selected by CCA programs. These portfolios show that CCA programs will independently select renewable resources that drive GHG reductions.

Fourth, the HCP demonstrates that a portfolio with new procurement almost entirely driven by CCA programs is *reliable*. Commission Staff has established that the HCP, driven by over 10,000 MW of new CCA procurement, would achieve a high level of grid reliability, with a Loss Of Load Expectation ("LOLE") of .003, a mark that significantly exceeds the accepted reliability standard of 0.1 LOLE.[5]

While the Joint CCAs support the adoption of the HCP for the PSP in this initial IRP cycle, the HCP is hampered by a number of flaws that should be remedied in the 2019-2020 IRP process. First, the HCP is flawed because it is based only on *conforming portfolios*, ignoring the *preferred portfolios* submitted by a number of CCA programs. While some CCA programs submitted a single portfolio that served as both their conforming portfolio and their preferred portfolio, a number of CCA programs submitted separate preferred and conforming portfolios. These preferred portfolios are more accurate than the conforming portfolios, since they represent CCA programs' actual planned procurement, rather than procurement based on the "menu" of options provided by the Reference System Plan ("RSP"), and in some cases are based on more accurate inputs and assumptions than the RSP. For instance, Pico Rivera Innovative Municipal Energy ("PRIME") submitted a preferred portfolio that included a significantly higher, and more

4 *Id*. at Slide 34.

accurate, load forecast. Similarly, MCE submitted a preferred portfolio with more accurate load forecast that reflects the high penetration of Behind the Meter ("BTM") solar resources expected in MCE's service area.

The use of CCA programs' preferred portfolios rather than their conforming portfolios is more consistent with the CCA programs' procurement independence set forth in statute and recognized by the Commission in this proceeding.[6] In addition, the use of CCA programs' preferred portfolios is consistent with the ultimate goal of achieving the State's GHG reduction goals. In future iterations of the IRP process, the Joint CCAs anticipate that a number of CCAs may, consistent with their own internal planning processes and environmental goals, submit preferred portfolios that include *more renewable resources* and *greater GHG reductions* than their conforming portfolios. In the next IRP cycle, the Commission should produce and perform production cost modeling on at least two versions of the HCP – one version based on aggregated conforming portfolios, and a second based on a combination of IOU conforming portfolios (recognizing the Commission's regulatory mandate and extensive authority to direct IOU procurement) and CCA preferred portfolios.

Second, the HCP is flawed by the use of broad "top-down" statewide inputs and assumptions, even when more accurate LSE-specific information is available. While the Joint CCAs do not oppose the use of statewide inputs and assumptions to develop high-level statewide projections, the Commission should recognize the inherent limitations of such broad-brush projections, and where available rely on more granular inputs, assumptions, and load forecasts developed by each LSE. For instance, as SCP noted in its 2017-2018 IRP Compliance Filing, a number of the elements of the Commission's 2017-2018 IRP methodology led to inaccurate

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5 *Id*. at 60, 67.

6 *See,* Pub. Util. Code Section 366.2(a)(5) ("a community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute"); Section 454.52(b)(3); D.18-02-018 at 26, 29-30.

projections for SCP due to the Commission's use of statewide rather than LSE-specific information.[7] For instance, the Commission used statewide California Energy Commission ("CEC") forecasts and assumptions to develop the 2017-2018 IRP's annual load forecast and to assign individual load forecasts to each LSE. Problematically, neither the IRP's statewide load forecast nor its LSE-specific forecast for SCP took into account SCP-specific assumptions regarding population growth, housing stock and fire rebuild efforts in Sonoma and Mendocino Counties, SCP opt-out rate, electric vehicle growth, other electrification, behind the meter solar, and expected energy efficiency.[8] The Commission's failure to incorporate these more accurate locally developed assumptions resulted in a significantly less accurate load forecast for SCP. In order to remedy this issue in future IRP cycles, the Commission should develop a process that starts with a statewide framework, but includes a mechanism for incorporating more accurate LSE-specific or area-specific information where such information is available.

Third, Commission Staff used different models to develop the RSP on the front end of the IRP process, and to assess the HCP on the back end. Specifically, staff used RESOLVE to develop the RSP, and a production cost model called SERVM to assess the consolidated LSE conforming portfolios. This led to some conflicting results, and a less accurate product than may otherwise have been achieved. While the Joint CCAs appreciate Staff's stated intent to work on ways to better align the two models, additional steps should also be taken. At a minimum, in future IRP cycles the Commission should use both RESOLVE and SERVM on the back end to evaluate the consolidated portfolios. In addition, it may be useful to use SERVM at the beginning of the IRP process to assess one or more potential conforming portfolios based on the RSP.

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[7] Sonoma Clean Power, *2018 IRP Integrated Resource Plan Exhibit A - Narrative* (Submitted August 1, 2018) at 5.

[8] *Id*.

Fourth, this IRP did not account for reasonably anticipated load migration from IOUs to CCAs (and potentially ESPs). This issue is discussed in detail in the Joint CCAs' response to Question 17, below. Remedying this issue should be one of the Commission's top priorities in the next IRP cycle. The Joint CCAs stand ready to work with Commission staff and other stakeholders to develop a reasonable, broadly acceptable methodology for projecting new CCA formation and IOU load departure through the IRP planning horizon.

Fifth, the HCP was developed by consolidating individual LSE conforming portfolios that were developed using templates that do not fully or accurately reflect LSE procurement. Specifically, the IRP templates did not include a clear way to account for "portfolio product" contracts. In portfolio product contracts, the seller agrees to provide the buyer with a certain amount of power, with certain specified environmental attributes, from a large pool of resources. With such contracts, the purchaser knows the amount of power provided and the attributes of that power, but not the specific asset(s) that provided that power. These products are *extremely common* in the California electricity market, and are offered by a range of vendors, including Pacific Gas and Electric Company ("PG&E"). Because these contracts are not neatly tied to a specific asset, they are somewhat difficult to account for in the generation unit-specific IRP process. However, given the fact that these contracts guarantee certain attributes – attributes that purchasers pay a premium for – these contracts should not be treated as generic system power and should instead accurately reflect the guaranteed attributes. In addition, in the next IRP cycle the template should include combined solar and storage projects.

In light of these significant issues, the Joint CCAs urge the Commission to adopt the HCP with the understanding that, while this first "trial run" iteration of IRP provides useful insights regarding broad trends, this iteration of IRP has revealed a number of issues that must be remedied in the 2019-2020 IRP cycle.

Question 2:

If you do not recommend the hybrid conforming portfolio form the basis of the PSP, what portfolio should the Commission utilize and why?

Response to Question 2:

The Joint CCAs recommend that the hybrid conforming portfolio be adopted as the basis of the PSP, subject to the above-listed issues being addressed in the next IRP cycle.

Question 3:

Are there reasons for the Commission to utilize a different portfolio (or portfolios) for transmission infrastructure planning (in the TPP) as distinct from the portfolio describing procurement actions of LSEs? Discuss.

Response to Question 3:

See the Joint CCAs' response to Questions 18 and 20, below.

Question 4:

Comment on whether or not the hybrid conforming portfolio is likely to result in a reliable system in 2030.

Response to Question 4:

The Joint CCAs agree with Commission Staff's conclusion that the HCP, a statewide portfolio driven in large part by over 10,000 MW of new renewable resource procurement by CCA programs, would be highly likely to result in a reliable system in 2030. The Joint CCAs believe that this conclusion will hold up in future iterations of the IRP cycle that more accurately account for local information and reflect CCA programs' planned procurement by aggregating CCA programs' preferred portfolios rather than their conforming portfolios.

Of particular interest to the Joint CCAs, the HCP includes a significant decrease in IOU procurement and increase in IOU reliance on system power through 2030. This increased reliance on system power does not reflect a procurement shortfall and should not raise any reliability concerns. The IOUs' plans to increase their reliance on system power going forward represents a strategy for hedging against reasonably expected load departure due to CCA formation. As discussed in the Joint CCAs' response to Question 17, below, this hedging strategy is entirely reasonable, and is consistent with the State's policy of protecting local choice, avoiding "on behalf of" procurement, and avoiding the complex and contentious problems created by stranded assets. As such, the IOUs' planned increasing reliance on system power should be viewed as proxy for expected load departure rather than an indication of any future reliability challenge. This reliance on system power (and any perceived shortfall created by this reliance) should disappear in future iterations of the IRP process as the Commission implements and refines a process that accounts for expected load departure, and CCA programs form or expand and procure on their new customers' behalf.

<u>Question 5</u>:

> *Are the adjustments made by staff to the geographic resource allocations proposed by LSEs to develop the hybrid conforming portfolio, as described in Section 2.1 above, warranted? What modifications would you make to these assumptions and why?*

<u>Response to Question 5:</u>

The Joint CCAs support the changes made by Staff to the geographic resource allocations proposed by LSEs. The geographic changes made by Staff involved only a small percentage of total expected procurement, and correct minor locational issues that were bound to come up. LSEs made their geographic resource choices without knowledge of the planned locations of other LSE's new resources. This fact, combined with the rough nature of the first iteration of the IRP process, means that LSEs' aggregated geographic resource allocations were almost certain to include some practical flaws. As CCA IRP plans move from planning toward execution, plans will self-correct to choose resources that are not transmission constrained. As a general matter, excess resources and resource potential should be available to meet expected demand. For instance, if Solano wind is oversubscribed, lots of excess wind resources are available in other areas.

LSEs are likely to differ significantly with regard to their priorities. Some LSEs may have little to no preference regarding the geographic location of a resource or resources, while others may have extremely strong interests in ensuring that their new procurement is located in a specific region or regions, without triggering unnecessary transmission upgrades. Similarly, while some parties may be fine with certain resources being re-designated as "energy only," this may raise significant issues for others. As such, the Joint CCAs appreciate that when aggregated portfolios showed that planned projects in an area exceeded transmission capacity or resource potential, the Energy Division contacted parties planning on building resources in those areas and gave willing parties the opportunity to either relocate or re-designate their projects. This practice should be continued in future iterations of the IRP process, and the Commission should continue to ensure that LSEs that view a project or project's location as "high priority" are accommodated to the greatest extent possible. This is especially true for CCA programs, which, as the Commission has recognized, retain procurement autonomy. If the Commission wants the IRP process to be truly accurate, the Commission should work to ensure that CCA IRP submissions reflect CCA programs' actual procurement plans (including locational preferences) without making unnecessary modifications to CCA portfolios.

Question 6:

> *Comment on the implications of the increased reliance on imports represented by the hybrid conforming portfolio.*

Response to Question 6:

As discussed in detail in response to Question 7, below, the Joint CCAs note that a large share of the imported power relied on by CCA programs' is imported hydroelectric power from the Pacific Northwest ("PNW"). As discussed below, the Joint CCAs agree with the Commission's conclusion that this planned reliance does not raise any legitimate resource availability, reliability, or transmission capacity concerns.

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Question 7:

> *Comment on the hydroelectric feasibility analysis conducted by staff. Should the Commission require additional or different approaches to reliance on hydroelectric resources? What are your specific recommendations?*

Response to Question 7:

The CCA programs strongly support the staff conclusions regarding the reasonableness of LSEs' planned procurement of PNW Hydro. This analysis is consistent with previous comments submitted by CalCCA in this proceeding:

> There is little doubt that the future procurement plans [of the CCAs] are feasible. The RESOLVE model documents 7,844 MW of large hydro capacity within CAISO with another 4,766 MW within other regions of California (e.g., Imperial Irrigation District and Los Angeles Department of Water and Power), and 38,370 MW within the Northwest and Southwest regions. As already indicated, approximately 4,000 MW of Large Hydro/ACS is already under contract in 2018 and more than adequate capacity should be available in future years based on expected re-contracting and the large amount of capacity in the RESOLVE model. Even assuming that the entire 1,000 MW of additional hydro resources planned by CCAs are expected from out-of-state Large Hydro, adequate transmission capacity appears available to meet those needs. More specifically, there is 4,800 MW and 3,100 MW of transmission capacity at the California Oregon Intertie and Pacific DC Intertie, respectively, which can adequately meet the planned CCA demands.[9]

These conclusions should be explicitly incorporated in the 2019-2020 IRP. In addition, the emissions factor for unspecified PNW imports should be modified to reflect their high average hydro content and relatively low GHG emissions compared to generic system power.

Question 8:

> *Comment on any actions the Commission should take to mitigate drought risk, especially for in-state hydroelectric resources.*

Response to Question 8:

To address and mitigate drought risk, in the next IRP cycle Commission Staff should, at a minimum, include low in-state hydroelectric year scenarios in the modeling.

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9 *Comments of California Community Choice Association on Integrated Resource Plans of Load Serving Entities* (September 12, 2018) at 3.

Question 9:

Comment on the potential for WECC-wide resource shuffling and how the Commission should address it.

Response to Question 9:

As a threshold matter, it is important that the Commission keep the question of resource shuffling in perspective. Some parties have been especially dogged about raising concerns regarding resource shuffling, voicing these concerns so often that it would be easy to mistakenly assume that resource shuffling has been established to be an actual problem. This, however, is simply not the case. The CCA Parties are unaware of any actual evidence on the record in this proceeding – or any other proceeding – that provides a concrete example of resource shuffling actually occurring. Prior to attempting to "fix" resource shuffling, stakeholders must first identify when and where it is happening. Absent this, any attempt by the Commission to address resource shuffling would be a solution in search of a problem.

Even if one could reasonably *speculate* that some renewable power imported into California could possibly be locally replaced with additional fossil generation, such conjecture would fall far short of concrete evidence of an actual problem, and would provide no insight regarding the (likely small) scope and impact of the problem if it actually does exist.

Further, there are strong reasons to believe that concerns regarding resource shuffling are either unfounded or, at the minimum, highly exaggerated. First, a significant share of the imported resources that CCA programs rely on are imports of PNW hydroelectric power. PNW hydroelectric providers have submitted comments explaining that their exports to California are primarily *excess* hydroelectric capacity.[10] In other words, the exports to California are not "shuffled" with any generation to meet local need. Further, any power exported from the PNW is unlikely subject to be "shuffled" with GHG-emitting fossil generation due to the PNW area's

[10] *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.

very high GHG-free resource portfolio. For instance, today only 11% of Washington State's unspecified fuel mix is from natural gas,[11] while by 2022 roughly *90%* of the energy generated in Washington State will be from GHG-free resources.[12]

Second, concerns regarding resource shuffling ignore the impact of environmental laws, policies, and goals adopted by other states, localities, and individual utilities. The California Air Resources Board ("CARB") specifically prohibits resource shuffling under its cap-and-trade program. The hydroelectric providers in the PNW are governed by the Northwest Power Act, which prohibits electricity generation providers from selling energy to out-of-state LSEs before serving their load in the PNW. In addition, these providers are subject to a number of state laws that reduce the likelihood of resource shuffling. For instance:

> Washington State's renewable portfolio standard will increase to 15% in 2020. Washington State also has GHG emission reduction goals to reduce GHG emissions to 1990 levels by 2020, and 25% below 1990 levels by 2035. Washington State is on track to meet or exceed these interim targets with the measures outlined above and is considering deeper de-carbonization goals consistent with the State of California.[13]

These policies are not limited to Washington State. Oregon has a 50% renewables portfolio standard ("RPS") for IOUs and a multi-sector Cap-and-Trade Program.[14] In light of these considerations, it is highly unlikely that hydroelectric providers have the ability to engage in resource shuffling, given the penalties associated with violating the CARB's regulations, the Northwest Power Act, and State RPS, cap-and-trade, and GHG-reduction requirements.

Third, concerns regarding resource shuffling ignore the economics of renewable power. Renewable power costs are dropping significantly, in some cases renewable power is actually more affordable than power from fossil plants.

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11 *Id*. at 4 (FN. 3).
12 *Id*. at 5.
13 *Id*.
14 *Id*.

Fourth, concerns regarding resource shuffling ignore the impact of increasing public awareness of climate change and growing customer demand for renewable energy outside of California (particularly in the PNW area).

All of these factors make it much more likely that hydroelectric power imported to California is either not needed to meet local need, or is likely to be "shuffled" *with other renewable power*.

Ultimately, there are limitations on what California's IRP process can measure and achieve. Concerns regarding increased GHG emissions in other states should be addressed by California in cooperation with the appropriate agencies of the state in question.

Question 10:

Comment on additional hydroelectric analysis that should be conducted in the future.

Response to Question 10:

The Joint CCAs agree with the Commission's conclusions regarding PNW hydro and do not believe that any further analysis in this IRP cycle is warranted. Staff's conclusions should be adopted 2019-2020 IRP cycle and used in developing the 2019-2020 RSP. In addition, as MCE and SCP argued in recent comments, in future iterations of the IRP process the Commission should use RESOLVE to project future PNW hydro availability.[15]

Question 11:

Comment on the calibrated LOLE study conducted for 2030. What are the implications or policy actions that should result, if any?

Response to Question 11:

The Joint CCAs believe that the calibrated LOLE study's conclusions are reasonable. The calibrated LOLE study's results do not require any action by the Commission in the 2017-2018 IRP cycle.

15 *Comments of Marin Clean Energy and Sonoma Clean Power Authority on Inputs and Assumptions for Development of the 2019-2020 Reference System Plan* (January 4, 2019) at 5.

Question 12:

> *Comment on the differences between the hybrid conforming portfolio and the portfolio associated with the RSP calibrated to the 2017 IEPR assumptions. What are the implications of these differences and how should they be addressed?*

Response to Question 12:

The CCA Parties view the differences between the HCP and the RSP as natural (and inevitable) differences between a centrally planned and projected portfolio and a portfolio that more accurately reflects LSEs' actual preferences.

If anything, the CCA parties are surprised and encouraged by how closely aligned the HCP and RSP turned out to be. The Commission should view the differences between the RSP and HCP as *improvements* to the RSP. The RSP is the portfolio selected as a result of statewide modeling. The HCP takes the broad perspective provided by the RSP and adds, to a limited extent, resource choices informed by individual LSEs' far more intimate and detailed knowledge of their operations, plans, and the specific needs of the communities and customers they serve. This is particularly true of CCA programs, which, by statute, are formed for the purpose of allowing local communities to choose their own energy/resource mix. Further improvements along these lines can be achieved in future IRP cycles using an HCP consisting of IOU conforming portfolios and CCA programs' preferred portfolios.

Question 13:

> *Comment on the criteria pollutant emissions results for the hybrid conforming portfolio. Is there further analysis that staff should conduct on criteria pollutant emissions for these high-level portfolio purposes? Explain.*

Response to Question 13:

The Joint CCAs do not have a response to Question 13 at this time, but reserve the right to comment on this matter going forward.

<u>Question 14</u>:

Comment on the GHG emissions results from the hybrid conforming portfolio analysis in SERVM. What are the implications and what should the Commission change as a result? (presuming that a new RSP will be analyzed in 2019-2020 already).

<u>Response to Question 14:</u>

The Commission should not take any action in the 2017-2018 IRP cycle based on the GHG emissions results from SERVM. This iteration of the IRP process has served its function and revealed problems to be addressed in future IRP iterations. The difference between SERVM and RESOLVE's GHG emissions projections for the RSP and the differences between SERVM's projections for the RSP and HCP are among these problems.

For the 2019-2020 IRP cycle, the Commission should make a range of corrections to the IRP process, including those discussed elsewhere in these comments. Among these changes, the Commission should take steps to further align SERVM and RESOLVE, and should use RESOLVE as the primary tool for assessing the HCP's emissions.

However, at the end of the day, SERVM and RESOLVE are different models that are designed to perform different functions. It is unlikely that the Commission will ever achieve perfect alignment of these different models' conclusions. As such, the Commission should use the models in a manner consistent with their primary intentions. RESOLVE should be the primary model used to develop the RSP and assess GHG emissions. SERVM should be a secondary (support) model used to assess costs and reliability of the aggregated portfolio. SERVM's GHG emissions results may provide some insights or a helpful "second opinion" but should not be relied upon as the primary measure of an aggregated portfolio's emissions.

<u>Question 15</u>:

Comment on the curtailment results of analyzing the hybrid conforming portfolio.

<u>Response to Question 15:</u>

The Joint CCAs do not have a response to Question 15 at this time, but reserve the right to comment on this matter going forward.

Question 16:

> *Should the Commission place additional or tighter requirements on LSEs filing IRPs in the next IRP cycle? Suggest specific requirements and explain your rationale.*

Response to Question 16:

The CCA Programs only respond to this question as it applies to CCA IRP submissions. "Additional" or "tighter" requirements on CCAs submitting IRPs are neither needed nor appropriate. As discussed in the Joint CCAs' response to Question 1, above, the HCP demonstrates that CCA Programs, working with the Commission, but ultimately making their own procurement decisions, can be counted on to achieve the State's GHG reduction, renewable energy, and reliability goals. The Joint CCAs recognize the incredible value that the IRP process provides CCA programs. Through IRP, the Commission has given CCA programs a set of tools and insights that will allow them to better plan future resource procurement and identify the resources that resources that most cost-effectively achieve state requirements, and, in many cases, their own more ambitious internal environmental goals. Empowered by this process, and working in coordination with the Commission, CCA programs can be counted on to exercise their independent procurement authority in a manner consistent with the state's goals without further Commission intervention.

In addition to being unnecessary, any "additional" or "tighter" requirements on CCA programs would be inappropriate. The Commission's role in certifying CCA IRPs is defined by statute (and further elaborated in D.18-02-018). Both Public Utilities Code Section 454.52 and this Decision include language that recognizes and preserves CCA programs' planning and procurement independence. Any "additional" or "tighter" requirements for CCA programs would almost certainly overstep this role and impinge on CCA programs' procurement independence.

<u>Question 17</u>:

Comment on any other aspects of the hybrid conforming portfolio analysis.

<u>Response to Question 17:</u>

The Ruling and Attachments note that the IOUs plan very little new procurement, and generally plan to increase their reliance on system power as their baseline resources retire or contracts expire.[16] The Commission notes that this is likely a strategy to avoid stranded assets in the event of future departing load. This hedging strategy is a *good thing*, and in future IRP iterations the Commission should develop a methodology for projecting CCA formation and IOU load departure, and actively encourage, if not require, that IOUs hedge against projected load departure.

Hedging against reasonably projected load departure avoids stranded assets with associated stranded costs that the IOUs would likely attempt to allocate to departing customers through cumbersome, inefficient, and highly contentious mechanisms like the Power Charge Indifference Adjustment ("<u>PCIA</u>") or some successor charge. In addition, hedging against reasonably projected load departure is consistent with CCA procurement independence and local choice, as it represents a reasonable step to avoid "on behalf of" procurement.

Load departure should be formally accounted for in IRP. In the 2019-2020 IRP cycle, one of the Commission's top priorities should be to work cooperatively with CCA programs, the IOUs and other interested parties to develop a formal methodology for projecting IOU load departure due to CCA formation. This methodology should allow the development of multiple scenarios with different levels of load departure for each IOU. In addition, the methodology, and IOU hedging strategies, should take the timing of expected load departure and lead-up times necessary for the development of various resource types into account. At an absolute minimum, the IRP should account for *announced* CCA formation. For instance, the City of San Diego has announced its intent to form a CCA program. In light of this announcement, the Commission should neither require nor allow San Diego Gas & Electric Company ("SDG&E") to plan for procurement on behalf of customers that will be served by the City's CCA program well before 2030.

II. RESPONSES TO QUESTIONS ON TPP PORTFOLIOS

Question 18:

> *Should the hybrid conforming portfolio be analyzed as the reliability base case in the 2019-20 TPP? Why or why not? What changes would you recommend? Comment on any other aspects of the hybrid conforming portfolio analysis.*

Response to Question 18:

The Joint CCAs support the use of the HCP as the reliability base case in the 2019-2020 TPP. However, given the rough nature of this first IRP cycle and the significant issues that need to be remedied in the next IRP cycle, the Joint CCAs recommend that no significant transmission modifications or investments be made based on the HCP. CAISO should defer any significant decisions until the 2019-2020 IRP portfolio is finalized.

Question 19:

> *Should the hybrid conforming portfolio be analyzed as the policy-driven base case in the TPP? Why or why not? What changes would you recommend?*

Response to Question 19:

The Joint CCAs do not have a response to Question 19 at this time, but reserve the right to comment on this matter going forward.

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[16] *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Portfolio and Transmission Planning Process Recommendations* (January 11, 2019), Attachment 2 at Slides 23, 35.

<u>Question 20</u>:

> *What are the potential implications if the CAISO analyzes the hybrid conforming portfolio and takes transmission investments to the CAISO Governing Board, if the resource procurement by LSEs between now and 2030 turns out to be significantly different than the hybrid conforming portfolio suggests? If this is a concern, suggest potential remedies or other analysis or actions that could be taken.*

<u>Response to Question 20:</u>

CAISO should not take any transmission investments based on the HCP to the CAISO governing board. The 2017-2018 IRP process is a practice run, and the HCP should be treated as a rough draft – informative, but not authoritative. Future iterations of the IRP are likely to be significantly more accurate, and CAISO has more than adequate time between now and 2030 for even long lead-time transmission projects.

<u>Question 21</u>:

> *Do you support the staff recommendation to transmit two policy-driven sensitivity scenarios (Case B and Case C) to the CAISO for further analysis as policy driven sensitivity scenarios? Why or why not? What changes would you make?*

<u>Response to Question 21:</u>

The Joint CCAs do not have a response to Question 21 at this time, but reserve the right to comment on this matter going forward.

<u>Question 22</u>:

> *Do you agree with the Commission staff assumptions used to develop policy-driven sensitivities, with respect to electric vehicle load, GHG emissions constraints in 2030, etc.? Explain in detail.*

<u>Response to Question 22:</u>

The Joint CCAs do not have a response to Question 22 at this time, but reserve the right to comment on this matter going forward.

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Question 23:

Comment on any other aspects of the Commission's recommendations to the CAISO for TPP purposes.

Response to Question 23:

The Joint CCAs do not have a response to Question 23 at this time, but reserve the right to comment on this matter going forward.

III. RESPONSES TO QUESTIONS ON COMMISSSION POLICY ACTIONS

Question 24:

What further policy or procurement actions should the Commission take as a result of the analysis presented in this ruling? Explain your recommendations in detail.

Response to Question 24:

The Commission should explicitly find that each CCA program's IRP adequately contributes to a statewide portfolio that achieves the goals of Senate Bill 350. As such, the Commission should certify each CCA program's IRP submission.

In addition, the Commission should find that the HCP as a whole, and in particular new procurement planned by CCA programs, satisfies the State's renewables integration resource need and each CCA programs' individual share of that need.

Question 25:

Is an increase in the RPS compliance requirement, beyond 60 percent RPS in 2030, warranted? Why or why not?

Response to Question 25:

An increase in the RPS compliance requirement beyond 60 percent RPS in 2030 is not warranted at this late point in the 2017-2018 IRP cycle. This question should be addressed in the 2019-2020 IRP cycle.

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<u>Question 26</u>:

Acknowledging that near- and mid-term reliability issues have been addressed in comments in response to a separate ruling in this proceeding, should the Commission order any resource procurement in the context of the IRP proceeding at this time? How much? Explain your rationale.

<u>Response to Question 26:</u>

The Commission should not order any procurement in the 2017-2018 IRP cycle.

IV. CONCLUSION

The Joint CCAs thank the Commission for its consideration of these comments.

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Respectfully submitted,

<u>/s/ David Peffer</u>

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