Regulatory Packet

Part 2

MCE98	EM&V	$30,029	$16,590	$111,143	$95,351
Portfolio Total	**Portfolio**	**$1,831,741**	**$1,347,788**	**$6,779,704**	**$2,262,703**

Table 4: Sector Authorized Budget and Actual Expenditures for Two Most Recent Years

	2018		**2019**	
Sector	**Authorized Budget**	**Actual Expenditures**	**Authorized Budget**	**Actual Expenditures**
Commercial	$838,745	$617,207	$1,185,725	$643,277
Cross-Cutting	$102,102	$35,114	$271,143	$95,351
Residential	$935,936	$695,467	$3,865,965	$1,317,213
Industrial	n/a	n/a	$690,423	$113,244
Agricultural	n/a	n/a	$766,449	$93,617
Portfolio Total	**$1,876,783**	**$1,347,788**	**$6,779,704**	**$2,262,703**

Table 5 shows MCE's authorized budgets and actual expenditures at the portfolio-level beginning with program year 2016.

Table 5: Rolling Portfolio Authorized Budgets and Actual Expenditures from 2016

Portfolio Year	**Authorized Budget**	**Expenditures**
2016	$1,586,347	$1,165,285
2017	$1,586,347	$1,403,313
2018	$1,876,783	$1,347,788
2019	$6,779,704	$2,262,703

Finally, Table 6 shows MCE's budget forecasts and annual budget caps for the relevant program year and each remaining year of the approved business plan period.[17]

Table 6: Budget Forecasts and Annual Budget Caps for 2021 and Remaining Years of Business Plan Period

Sector	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**[18]
Residential	$2,733,236	$6,170,017	$6,170,017	$6,170,017	5,660,017	$30,941,731
Commercial	$3,010,541	$2,934,922	$2,934,922	$2,934,922	$3,251,922	$17,804,713
Industrial	$871,077	$1,269,596	$1,269,596	$1,260,596	$1,260,596	$8,316,550
Agriculture	$468,195	$1,181,259	$1,181,259	$1,181,259	$1,260,259	$6,053,310
WE&T	$361,481	$346,667	$346,667	$346,667	$346,667	$2,094,815
Finance	$0	$0	$0	$0	$0	$18,524
Subtotal	$7,444,530	11,902,460	$12,091,865	$11,902,460	$11,779,460	$65,229,642
EM&V	$119,113	$189,405	189,405	$189,405	$187,405	$1,0195,469

[17] The all-inclusive business plan budget forecasts, annual caps, and savings true-up tables is included as an attachment.

[18] Total represents actual expenditures through 2020 plus budget forecasts for the remainder of the business plan period.

Total Portfolio Program Year PA Budget	$7,563,643	$12,091,865	$12,091,865	$12,091,865	$11,966,865	$66,325,111[19]
Total Authorized Portfolio PY Budget Cap	$12,404,000	$10,998,000	$10,998,000	$10,998,000	$10,870,000	$85,736,000

(2) Energy Savings

D.18-05-041 stated that MCE's forecasted energy savings goals must meet or exceed the annual energy savings targets included in the business plan.[20] Subsequently, MCE submitted budget and energy savings true-up tables in the 2019 ABAL that more accurately reflect the planning assumptions and forecasts for each program year through the business plan period.[21] In D. 19-08-034, *Decision Adopting Energy Efficiency Goals for 2020-2030*, the Commission directed MCE that for each year that MCE requests EE funding authorization via an ABAL, MCE shall meet or exceed the annual savings forecasts presented in the true-up tables as submitted in MCE's PY 2019 ABAL (and subsequently approved in Energy Division's advice letter disposition).[22]

In table 7 below, MCE provides forecasted net energy savings and goals for each program for PY 2021.

Table 7: Program-Level Forecasted Net Energy Savings for 2021

Program	Program ID	Net kWh	Net kW	Net Therm
MF Comprehensive	MCE01	133,958	40	12,908
Commercial	MCE02	5,224,085	273	88,905
SF Comprehensive	MCE07	6,093,680	0	0
SF Direct Install	MCE08	105,507	19	51,318
Industrial	MCE10	1,359,837	33	129,523
Agricultural	MCE11	863,147	112	14,296
WE&T	MCE16	0	0	0
EM&V	MCE98	0	0	0
Total		**13,780,213**	**477**	**296,950**

Table 8 shows claimed energy savings of each program and the total portfolio beginning with 2016.

Table 8: Program-level claimed energy savings beginning with 2016

Year	Program	Program ID	Net kWh	Net kW	Net Therm
2016	MF Comprehensive	MCE01	254,444	24	8,112
2016	Commercial	MCE02	310,753	62	12

[19] Funding levels through 2025 do not exceed the overall funding amount authorized in D.18-05-041, which caps PAs' total spending for the period 2018-2025.

[20] D.18-05-041 at p.134.

[21] MCE Advice Letter 33-E pp.9-11

[22] D.19-08-034 at p.28.

2016	SF Seasonal Savings	MCE03	0	0	0
2016	Financing	MCE04	0	0	0
2017	MF Comprehensive	MCE01	134,084	16	7,541
2017	Commercial	MCE02	1,077,926	202	754
2017	SF Seasonal Savings	MCE03	50,233	5	26,526
2017	Financing	MCE04	0	0	0
2018	MF Comprehensive	MCE01	151,217	8	16,468
2018	Commercial	MCE02	823,364	126	-889
2018	SF Seasonal Savings	MCE03	185,010	19	54,801
2018	Financing	MCE04	0	0	0
2018	EM&V	MCE98	0	0	0
2019	MF Comprehensive	MCE 01	156,391	19	10,591
2019	Commercial	MCE02	1,005,902	211	-6,193
2019	SF Seasonal Savings	MCE03	344,212	0	112,363
2019	MF Direct Install	MCE05	41	0	4
2019	SF Comprehensive	MCE07	0	0	0
2019	SF Direct Install	MCE08	6,110	0	1,166
2019	Industrial	MCE10	0	0	0
2019	Agricultural	MCE11	0	0	0
2019	WE&T	MCE16	0	0	0
2019	EM&V	MCE98	0	0	0
		Total	**4,449,687**	**692**	**231,256**

Table 9 shows MCE's forecasted, claimed, and evaluated energy savings at the portfolio-level beginning with PY 2016. MCE's portfolio has not been evaluated since the beginning of the rolling portfolio.

Table 9: Portfolio-level forecasted, claimed, and evaluated savings beginning with 2016

	Forecasted			**Claimed**			**Percent of Goal Achieved**			**Evaluated**
Year	**Net kWh**	**Net kW**	**Net Therm**	**Net kWh**	**Net kW**	**Net Therm**	**Net kWh**	**Net kW**	**Net Therm**	
2016	n/a	n/a	n/a	565,198	87	8,124	n/a	n/a	n/a	n/a
2017	1,812,755	351	33,850	1,262,243	223	34,821	70	64	103	n/a
2018	1,846,948	349	70,289	1,159,591	153	70,381	63	44	100	n/a
2019	5,852,476	592	403,832	1,512,656	230	117,931	26	39	29	n/a

Pursuant to D.18-05-041, PAs also need to report on greenhouse gas ("GHG") savings forecasts and actuals since the beginning of the rolling portfolio.[23]

Table 10: GHG savings forecasts and actuals beginning with 2016

Year	**GHG Forecast and Goal (Metric Tons CO_2)**	**Actual GHG Savings (Metric Tons CO_2)**
2016	n/a	300

[23] Pursuant to D.18-05-041, at p. 127.

2017	919	750
2018	507	516
2019	3,071	1,417

(3) Cost-Effectiveness

Decision 18-05-041 provided guidance to Commission staff on how to evaluate PAs' ABALs, which included guidance on portfolio cost effectiveness. For PYs 2019-2022, PAs' portfolios must meet a forecasted TRC at or above 1.0. For PYs 2023-2025, PAs' portfolios must meet a forecasted TRC at or above 1.25. In the event a PA does not meet a TRC of 1.25 on a forecast basis for PYs 2019-2022, ABALs must contain additional discussion about how the PA intends to meet or exceed a 1.0 TRC on an evaluated basis.[24]

Tables 11, 12 and 13 show MCE's forecasted program-, sector-, and portfolio-level TRC, PAC, and RIM without market effects for PY 2021.

Table 11: Forecasted Program-Level TRC, PAC and RIM for PY 2021

	Program ID	TRC	PAC	RIM
Multifamily Comprehensive	MCE01	0.48	0.54	0.54
Commercial	MCE02	1.33	1.45	1.45
Single Family Comprehensive	MCE07	1.06	1.06	1.06
Single Family Direct Install	MCE08	0.31	0.31	0.31
Industrial	MCE10	1.86	2.27	2.27
Agricultural	MCE11	1.77	2.13	2.13
Workforce, Education and Training (WE&T)	MCE16	0.00	0.00	0.00
MCE EM&V	MCE98	0.00	0.00	0.00

Table 12: Forecasted Sector-Level TRC and PAC for PY 2021

Sector	TRC	PAC	RIM
Residential	0.53	0.54	0.54
Agricultural	1.77	2.13	2.13
Commercial	1.33	1.45	1.45
Industrial	1.86	2.27	2.27
WE&T	0.00	0.00	0.00

Table 13: Forecasted Portfolio TRC, PAC, and RIM for PY 2021

TRC	1.08
PAC	1.17
RIM	1.17

[24] D.18-05-041 at pp. 132-37.

Cost-Effectiveness Challenges

Forecasting a portfolio TRC of 1.25 is especially challenging for 2021. MCE identified a set of factors that resulted in a TRC forecast below 1.25 in 2021.

COVID-19 Impacts

The COVID-19 pandemic has impacted energy consumption and therefore energy savings potential. This impact varies significantly by customer sector, programs, and individual customers. Overall, residential energy consumption has increased while commercial energy consumption has decreased dramatically. This creates challenges forecasting and measures savings for normalized metered energy consumption ("NMEC") and pay-for-performance programs. It is also difficult to predict customers' willingness and motivation to participate in EE programs as the pandemic continues.

COVID-19 has created additional program planning work for PAs and implementers to assess the impacts on EE programs and to adjust delivery strategies to continue serving customers. MCE's response over the last 5 months includes (1) developing new models and methodologies to assess the impacts of COVID-19 on MCE's operations and programs; (2) working with implementers to assess impacts on their operations and program participants, and identifying new and innovative approaches to make programs accessible to customers; and (3) identifying EM&V impacts and modifications. These activities will continue beyond 2020.

Cost-Effectiveness Framework

The TRC test as currently implemented does not appropriately value energy efficiency. Non-energy costs, such as the net participant cost or costs from non-resource/ equity programs are included in the TRC while their non-energy benefits ("NEBs") are not considered. The asymmetry between costs and benefits shrinks the pool of available cost-effective savings to the point where it is difficult to both be cost effective and achieve aggressive energy savings goals.

Furthermore, pursuing a 1.25 TRC at a portfolio level requires making cuts to services that help our most disadvantaged customers, for example a multifamily EE program that serves affordable properties, or a residential direct install program that provides no cost upgrades to middle income customers who cannot afford to invest in EE.

Avoided Cost Calculator Updates

The timing and uncertainty of the avoided costs calculator ("ACC") updates do not allow PAs the opportunity to perform proper portfolio planning to ensure a cost-effective filing. The ACC updates were adopted on June 25, 2020 and subsequently incorporated into CEDARS production on July 16, 2020. At that point in time, MCE was already well into the portfolio planning process as a draft of the ABAL was due to CAEECC on July 27, 2020 for the ABAL presentation on August 5, 2020. Hence, MCE had to rely on the previous ACC version to forecast its portfolio for the 2021 program year and then had to re-evaluate portfolio cost-effectiveness once the updated ACC was released on July 16. This process not only creates double work for PAs, but also leads to significant uncertainty that undermines long-term planning abilities. It is usually difficult to predict the magnitude or direction of the annual ACC update, which until this year had significant negative impacts on PAs' portfolios. Many programs require more than one year to plan, launch, develop a pipeline and see projects through to completion.

Workpaper Updates

2019 was a major workpaper update year as the IOUs transitioned their separate workpapers into statewide workpapers for the 2020 PY. For PAs that were not involved in the workpaper process (i.e., non-IOU PAs), it was exceedingly difficult to track workpaper updates and impact on programs. As of recently, MCE and PG&E have established a workpaper coordination process to make the process more transparent. However, work still remains to improve the workpaper submission, review, and approval process so that it is transparent to all PAs.

Strategies to Increase Cost-Effectiveness in 2021

While no one can predict the extent and impact of the COVID-19 pandemic at this point in time, we are continuing to adapt and are committed to serving our customers well during this uncertain time. MCE believes the following strategies will contribute to a strong portfolio performance in 2021.

Program Launches and Ramp Up

- MCE has launched and ramped up five new programs since Business Plan approval and expects to generate savings from those programs in 2020 and 2021. MCE's residential Single-Family Comprehensive Program, as well as the non-residential programs, are expected to deliver cost-effective savings to help offset some of the less cost-effective programs in MCE's portfolio.
- MCE is preparing to roll out EE programs to MCE's two newest communities - Pleasant Hill and Vallejo.

New Implementation Strategies

- The modifications to the former three-prong-test have paved a way for the inclusion of fuel substitution measures in EE portfolios. MCE is incorporating fuel substitution measures into its 2021 portfolio as a viable long-term strategy for California to meet its carbon reduction goal.
- Most custom and deemed EE programs focus on above code savings, using code and industry-standard practice ("ISP") as baselines to determine savings. By using NMEC, MCE can focus on increasing the energy efficiency of existing buildings in its commercial sector to unlock to-code savings that are often left stranded. Additionally, this population-level NMEC component will align EE procurement with the program's delivered net benefits, by incentivizing time-dependent savings, thoughtful measure selection, and customer targeting focused on load shape and demand profiles.
- MCE deployed Strategic Energy Management ("SEM") and Behavioral Retro commissioning, and Operational ("BROs") participation pathways in its EE programs. MCE designed these participation pathways to help large Industrial, Agricultural, and Commercial customers overcome the multiple barriers associated with cost-effective EE investments.
- MCE improved program coordination and referral systems with other partner programs to improve cost-effectiveness without limiting opportunities for customers.

AMI Analytics

- MCE is leveraging new AMI data flows and analytics tools to understand COVID-19 impacts. With AMI data available from across our service area, and an effective project "start" date (when shelter in place orders took effect), MCE now has insights into the highly variable load shape and demand impacts that COVID-19 has had on our non-residential customers - in aggregate and by sector. Insights from the COVID-19 analytics work will be applied to program implementation and planning.

Cost-Effectiveness Information for Previous Program Years

Tables 14, 15 and 16 show MCE's forecasted, claimed, and evaluated cost-effectiveness information at the program-, sector-, and portfolio-level for the most recent years. The cost-effectiveness of MCE's portfolio has not been evaluated since the beginning of the rolling portfolio, 2016.

Table 14: Program Claimed TRC and PAC for PYs 2018 and 2019

Year	Program	TRC Ratio	PAC Ratio
2018	Commercial	1.04	1.21
2018	Multifamily	0.12	0.67
2018	Single Family	0.80	0.80
2019	Commercial	0.48	0.49
2019	Multifamily	0.21	0.4
2019	Single Family	2.12	2.12
2019	Multifamily DI	0.00	0.00
2019	Single Family DI	0.09	0.09

Table 15: Sector Claimed TRC and PAC for PYs 2018 and 2019

Year	Sector	TRC	PAC
2018	Commercial	1.04	1.21
2018	Residential	0.15	0.69
2018	Cross-Cutting	0.00	0.00
2019	Commercial	0.48	0.49
2019	Residential	0.24	0.33
2019	Cross-Cutting	0.00	0.00
2019	Industrial	0.00	0.00
2019	Agricultural	0.00	0.00

Table 16: Forecasted, Claimed, and Evaluated TRC and PAC beginning with 2016

Year	Forecasted TRC[25]	Claimed TRC	Forecasted PAC	Claimed PAC	Evaluated TRC[26]	Evaluated PAC
2016	n/a	0.27	n/a	0.48	n/a	n/a
2017	0.91	0.65	1.01	0.96	n/a	n/a
2018	0.58	0.31	0.64	0.91	n/a	n/a

[25] Program Administrators did not file ABALs for program year 2016.

[26] MCE's portfolio cost-effectiveness has not been evaluated since the beginning of the rolling portfolio, 2016.

2019	1.04	0.27	1.18	0.33	n/a	n/a

(4) Proposed Portfolio and Program Changes

Contrary to previous years, MCE is not proposing any new programs for 2021. MCE describes below some of the program-level changes that will improve MCE's portfolio savings, cost effectiveness, and workforce quality standards in 2021.

Multifamily Direct Install Program

The Multifamily Direct Install program provides no-cost EE measures to eligible homeowners and tenants in multifamily dwellings in MCE's service area. This program targets (but is not limited to) customers in Disadvantaged Communities ("DACs") whose household income exceeds 200% of the Federal Poverty Guidelines ("FPG"). The targeted group's income exceeds the limit to receive services through programs like PG&E's Energy Savings Assistance Program ("ESA") and MCE's Low-Income Families and Tenants ("LIFT") Program,[27] yet customers are still income constrained (lower middle-income). While there is no income cap to participate in the program, the program targets renters in particular neighborhoods to ensure that lower middle-income customers are reached. The goal is to introduce this market sector to the concepts of energy efficiency, provide upgrades that reduce household energy consumption and encourage a pathway toward deeper energy retrofits offered through existing and emerging market rate programs and technologies. EE measures included low-flow showerheads (with and without thermostat), shower restriction valve, kitchen faucet aerators, and 11W screw-in LEDs. The program also offers a limited number of electric heat pump replacement for electric water heaters.

MCE will end this program in 2020 for several reasons. First, the program overlaps with MCE's existing Multifamily Comprehensive program and other Multifamily Direct Install programs already in the market. Secondly, the program is not cost effective as a result of low participation, limited deemed measure offerings due to workpapers expiring, and COVID-19 impacts.

Single Family Seasonal Savings Program

This program offered 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 were offered the program on their thermostat and/or through a phone app and had to opt-in to participate.

MCE decided to end this program in 2019 after the ABAL was filed due to the fact that MCE was not able to secure an updated contract with the existing implementer.

Commercial Upgrade Program

The Commercial Upgrade Program targets commercial customers in MCE's service area. Its primary objectives are to facilitate the uptake of high-quality EE projects, and to improve the technical capability, pricing and program experience of both customers and the local contractor community. The program aims to achieve these objectives by supporting customers and contractors in the development of their projects – including equipment specification, incentives and technical assessments – but also by providing a number of participation pathways that

[27] Savings and costs associated with MCE's Low-Income Families and Tenants (LIFT) program are not included in the 2021 energy efficiency portfolio.

streamline the program experience and maximize customer benefit. The program is not restricted to a deemed measure list, or program-mandated business size or load requirements. Instead, the program is open to nearly any non-residential customer and provides varied participation pathways which include deemed, custom, NMEC and SEM. The program contracts with multiple implementation partners in the delivery of this program. Common measures include interior and exterior LED luminaires and lamps, networked lighting controls, connected thermostats, HVAC equipment, advanced rooftop controllers, ductless heat pumps, heat pump water heaters and other measures which may apply to customers in retail, office, and other non-residential building types.

MCE expects an expansion of the Commercial Upgrade Program in 2020 and 2021, primarily rooted in the development of population-level NMEC portfolios.

Single-Family Comprehensive Program

In May 2020, MCE launched a downstream program for selected eligible customers to receive Home Energy Reports ("HERs") at regular intervals to encourage energy- and money-saving behavioral changes. The program's treatment group will receive a series of HERs and, if enrolled in the digital platform, digital energy budget reports and alerts, as well as access to a web portal where they can learn about additional savings potential.

MCE is expanding the SF Comprehensive program to include behavioral messaging to an additional one hundred thousand customers in 2021.

Workforce, Education, and Training ("WE&T")

In May 2020, MCE's WE&T program was launched. The scope of work includes three elements: workforce engagement, MCE program-participating contractor engagement, and new workforce development. MCE and its program implementer will leverage existing relationships with industry groups to facilitate roundtable events that can increase the interest, and subsequent participation of residential contractor companies and their staff in high-performance building training. Outreach efforts will include participating contractors from disadvantaged communities and minority-focused groups to ensure diversity, equity, and inclusion. MCE will also leverage relationships with participating contractors and other vendors to gain insight into the barriers to electrification and high-performance building work. Furthermore, MCE aims to provide contractors who participate in MCE programs with the fundamental building performance knowledge they need to understand how to deliver maximum value and performance within their trade. MCE will provide participating contractors with field mentorships. Based on industry roundtables and field mentoring, MCE will establish a priority list of electrification topics for which there is an additional training need and will develop and deliver workshops for each of the identified topics.

Finally, MCE will prepare an internship program to provide job seekers home performance, energy efficiency, and safety with on-the-job training in their desired specialty. The internship component is expected launch in 2021.

(5) Metrics

Pursuant to D.18-05-041, MCE reported on sector-level metrics and their associated targets for program years 2018 and 2019 in its EE Annual Report submissions.[28] They can be found in spreadsheet form on the CPUC's data reporting website, Energy Efficiency Statistics ("EEStats").[29]

Conclusion

MCE respectfully requests that the Commission approve its 2021 EE portfolio budget of $7,563,643 effective as of January 2, 2021, for MCE's approved EE programs.

Notice

A copy of this AL is being served on the official Commission service lists for Application 17-01-013, *et al*. and Rulemaking 13-11-005.

For changes to these service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Protests

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address as above).

In addition, protests and all other correspondence regarding this AL should also be transmitted electronically to the attention of:

Jana Kopyciok-Lande
Senior Policy Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Ave.
San Rafael, CA 94901
Phone: (415) 464-6044
Facsimile: (415) 459-8095

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[28] See OP 9 of D.18-05-041.

[29] See MCE's 2018 and 2019 Annual Report Narrative and Excel at: https://eestats.cpuc.ca.gov/Views/Documents.aspx

jkopyciok-lande@mceCleanEnergy.org

Alice Havenar-Daughton
Director of Customer Programs
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ahavenar-daughton@mceCleanEnergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

Correspondence

For questions, please contact Jana Kopyciok-Lande at (415) 464-6044 or by electronic mail at jkopyciok-lande@mceCleanEnergy.org.

/s/ Jana Kopyciok-Lande

Jana Kopyciok-Lande
Senior Policy Analyst
MARIN CLEAN ENERGY

ATTACHMENTS

- Attachment 1: Marin Clean Energy Supplemental Budget Showing
- Attachment 2: Marin Clean Energy Program Changes Explanation Tables
- Attachment 3: Marin Clean Energy Budget and Savings True-up Tables
- Attachment 4: Marin Clean Energy CEDARS Filing Submission Receipt

cc: Service Lists: R.13-11-005; A17-01-013, *et al*.

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Jana Kopyciok-Lande
Phone #: 415-464-6044
E-mail: jkopyciok-lande@mcecleanenergy.org
E-mail Disposition Notice to: jkopyciok-lande@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 45

Tier Designation: 2

Subject of AL: Marin Clean Energy's 2021 Energy Efficiency Annual Budget Advice Letter

Keywords (choose from CPUC listing): Energy Efficiency, Compliance

AL Type: ☐ Monthly ☐ Quarterly ☑ Annual ☐ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.15-10-028 and D.18-05-041

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information: N/A
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information: N/A

Resolution required? ☐ Yes ☑ No

Requested effective date: 10/1/20

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1] Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division Attention: Tariff Unit 505 Van Ness Avenue San Francisco, CA 94102 Email: EDTariffUnit@cpuc.ca.gov	Name: Jana Kopyciok-Lande Title: Senior Policy Analyst Utility Name: Marin Clean Energy Address: 1125 Tamalpais Ave City: San Rafael State: California Zip: 94901 Telephone (xxx) xxx-xxxx: 415-464-6044 Facsimile (xxx) xxx-xxxx: Email: jkopyciok-lande@mcecleanenergy.org
	Name: Alice Havenar-Daughton Title: Director of Customer Programs Utility Name: Marin Clean Energy Address: 1125 Tamalpais Ave City: San Rafael State: California Zip: 94901 Telephone (xxx) xxx-xxxx: 415-464-6030 Facsimile (xxx) xxx-xxxx: (415) 459-8095 Email: ahavenar-daughton@mcecleanenergy.org

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

Attachment 1: Marin Clean Energy Supplemental Budget Showing

I. DESCRIPTION OF IN-HOUSE EE ORGANIZATIONAL STRUCTURE & ASSOCIATED COSTS

A. Narrative description of in-house departments/organizations supporting MCE's EE portfolio

1. Functions conducted by each department/organization

MCE provides the following table to summarize the functions conducted by each in-house department based on the functional groups defined in the "Functions Definitions" in Appendix B.

Table 1: Functions Conducted by Departments Supporting MCE's EE Portfolio[1]

Function	Customer Programs	Regulatory and Legislative Policy & Legal *	Technology & Analytics	Public Affairs *
Policy, Strategy, and Regulatory Reporting Compliance	x	x		
Program management	x			
Engineering Services				
Customer Application/Rebate and Incentive Processing	x			
Inspections				
Portfolio Analytics	x			
EM&V	x			
ME&O	x			x
Account Management / Sales				x
IT			x	
Call Center				
Incentives				

* These departments do not recover costs from the energy efficiency program budget.

2. Management structure and organization chart

MCE provides organizational charts for each department supporting the energy efficiency portfolio in Appendix A. These charts include the entire staff within

[1] These departments do not recover costs from the energy efficiency program budget.

each department even though only a subset of each team provides support to the energy efficiency portfolio. The management structure is represented on these organizational charts.

3. Staffing needs by department/organization

MCE's org charts are provided in Appendix A. MCE hired one Manager of Customer Programs in 2019 to support the energy efficiency portfolio. MCE does not anticipate hiring additional Customer Programs staff to support energy efficiency programs beyond what is provided in the organization chart. The staffing needs for the Customer Programs department and other departments at MCE may change in the future. Staff changes to other departments are unlikely to be driven by the need to support energy efficiency functions. As a result, MCE doesn't project long term growth in those departments related to supporting the energy efficiency portfolio.

4. Non-program functions currently performed by contractors

MCE currently works with contractors to support program reporting and measurement and verification (M&V).

5. Anticipated drivers of in-house cost changes by department/organization

MCE's in-house costs largely consist of staffing costs and since there are no further staffing changes planned for 2021, in-house cost should stay relatively steady.

6. Explanation of method for forecasting costs

MCE's Customer Program team developed a bottom-up budget and savings forecast using portfolio costs from 2019 and 2020. Additionally, over the last five months, MCE tracked and assessed COVID-19 impacts on program operations to inform costs and savings forecasted in the 2021 Annual Budget Advice Letter ("ABAL").

B. Table showing MCE's "Full-Time Equivalent" headcount by department/organization

MCE provides this table in Appendix B.

C. Table showing costs by functional area of management structure

MCE provides this table in the: (1) Residential Budget Detail; (2) Commercial Budget Detail; (3) Industrial Budget Detail; (4) Agricultural Budget Detail; (5) and Cross-Cutting Budget Detail of Appendix C.

D. Table showing cost drivers across the EE organization

MCE's 2021 budget request is 9% higher than its 2020 authorized budget. However, MCE expects to underspend its 2020 budget due to the COVID-19 pandemic.

E. Allocation of labor and O&M costs

MCE staff complete timesheets on which they designate the number of hours spent on EE activities. For employees who work on both EE and non-EE work, labor costs are billed proportionally based on hours recorded on staff timesheets for each activity.

The costs for the time spent on EE activities are reimbursed from the EE Programs Account. This account draws on the awarded energy efficiency budget. Costs from other departments that support MCE's EE portfolio are not reimbursed from the EE Programs Account. Those departments are fully supported from the General Operating Account (funded by generation service revenues).

Labor costs charged to EE are fully loaded. Benefit-related expenses for MCE employees who bill time to the EE program are paid from the EE Programs Account proportionate to the amount of time they spend on EE Programs. These costs are incorporated into the "fully-burdened" cost MCE charges to the EE reimbursable account as aforementioned.

Non-labor resources that support EE and non-EE activities are paid for entirely using non-EE funds from the General Operating Account (funded by generation services revenues). The only non-labor resources that are paid for with EE funds are those that exclusively support EE.

All O&M costs are paid for with non-EE funds from the General Operating Account (funded by generation service revenues), unless they exclusively support EE, in which case they are paid for using EE funds.

II. BUDGET TABLES INCLUDING INFORMATION IDENTIFIED IN THE SCOPING MEMO

A. Attachment-A, Question C.8

"Present a single table summarizing energy savings targets, and expenditures by sector (for the six specified sectors). This table should enable / facilitate assessment of relative contributions of the sectors to savings targets, and relative cost-effectiveness."

MCE's Customer Program team developed a bottom-up budget and savings forecast using portfolio costs from 2019 and 2020. Additionally, over the last five months, MCE tracked and assessed COVID-19 impacts on program operations to inform costs and savings forecasted in the 2021 Annual Budget Advice Letter ("ABAL").

B. Attachment-A, Question C.9

"Using a common budget template developed in consultation with interested stakeholders (hopefully agreed upon at a "meet and confer" session), display how much of each year's budget each PA anticipates spending "in-house" (e.g., for administration, non-outsourced direct implementation, other non-incentive costs, marketing), by sector and by cross-cutting program."

MCE has provided the request information in Appendix E. MCE developed a staffing budget based on our projected staffing needs. The distribution of staffing costs across budget categories for 2021 is based on the allocation in 2019 with some adjustments for areas in which we expect staff involvement to increase. The allocation of staffing costs for 2019 is based on staff estimations for the requested budget categories.

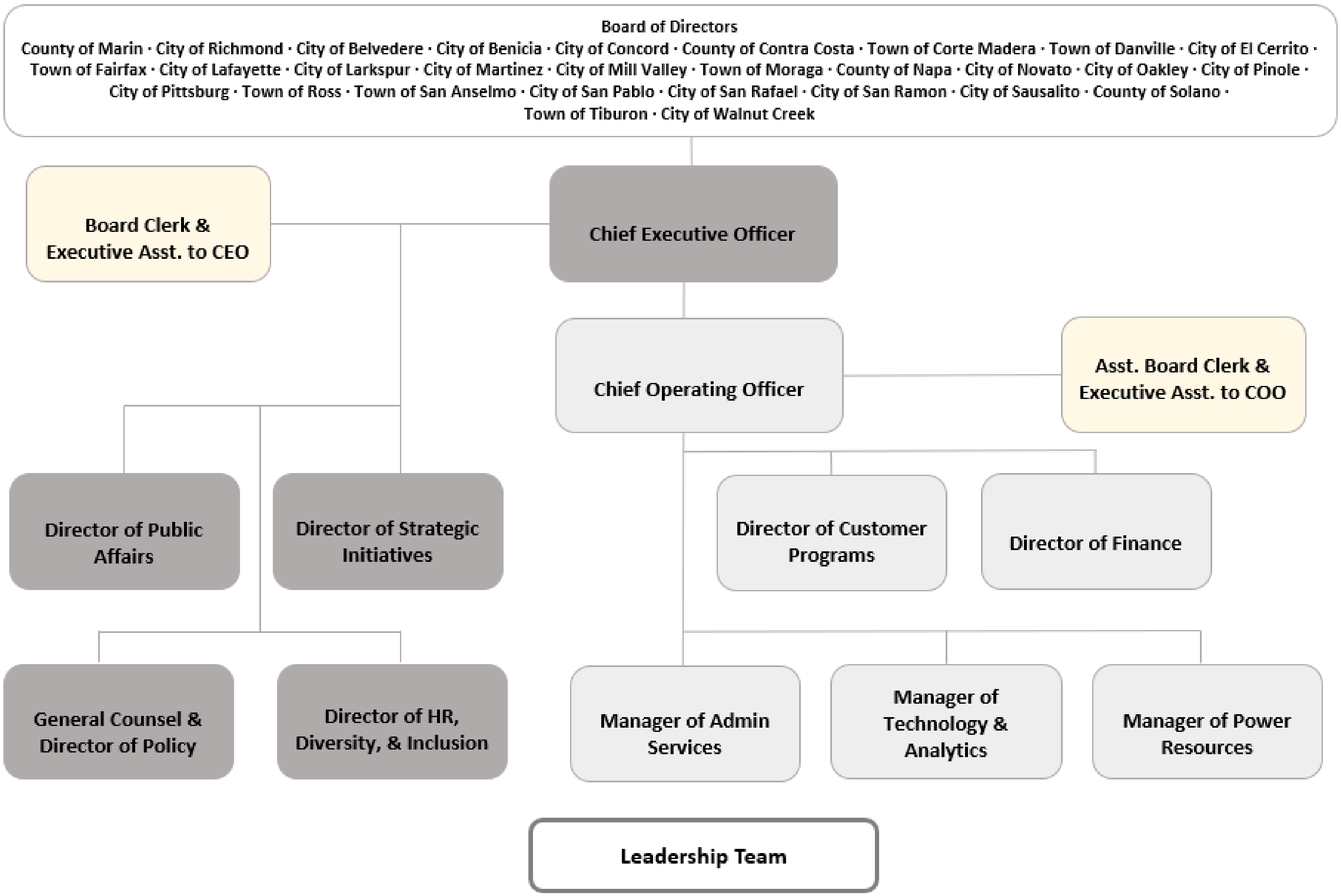
C. Attachment-A, Question C.10

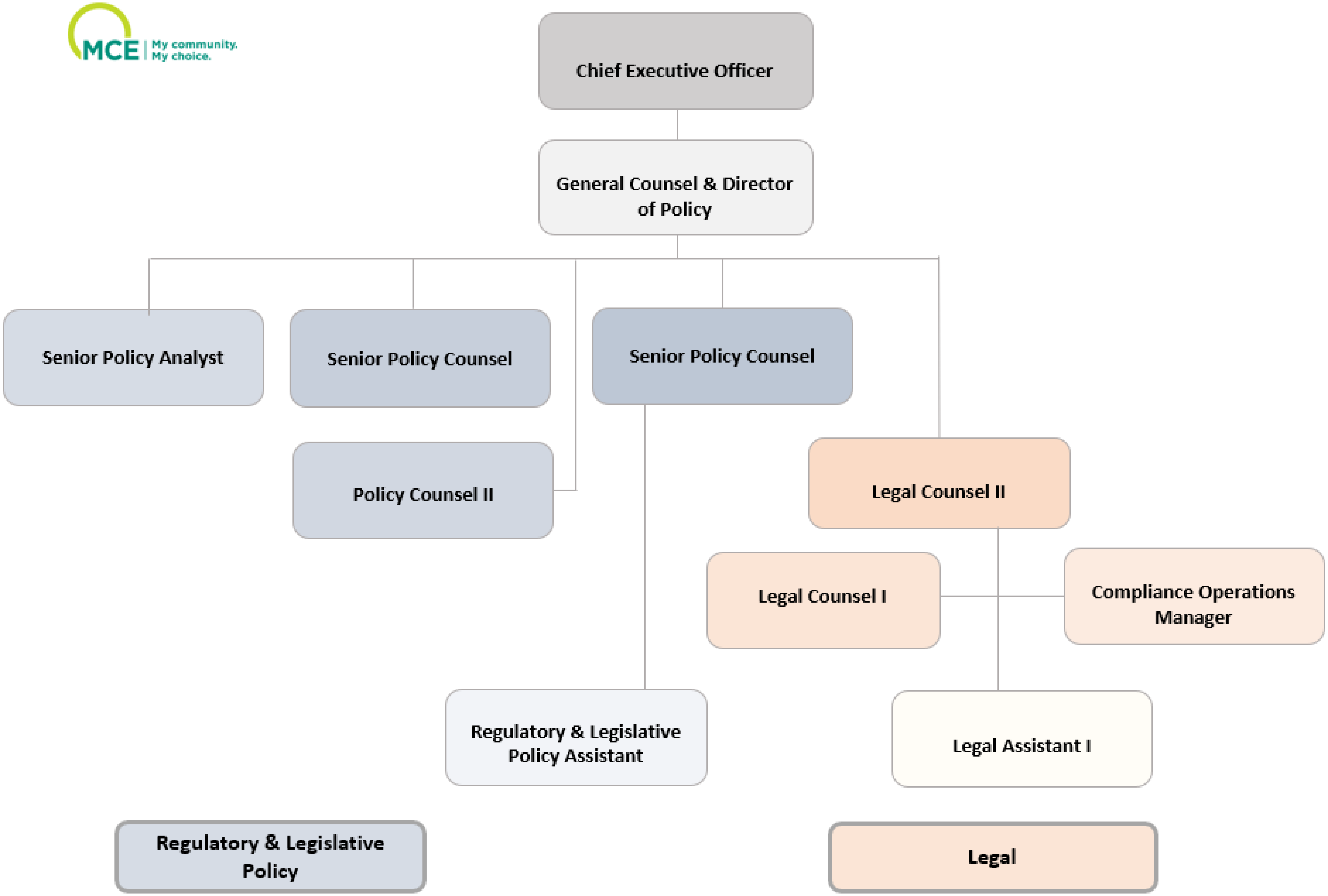
"Present a table akin to PG&E's Figure 1.9 (Portfolio Overview, p 37) or SDG&E's Figure 1.10 (p. 23) that not only shows anticipated solicitation schedule of "statewide programs" by calendar year and quarter, but also expected solicitation schedule of local third-party solicitations, by sector, and program area (latter to extent known, and/or by intervention strategy if that is more applicable). For both tables, and for each program entry on the calendar, give an approximate size of budget likely to be available for each solicitation (can be a range)."

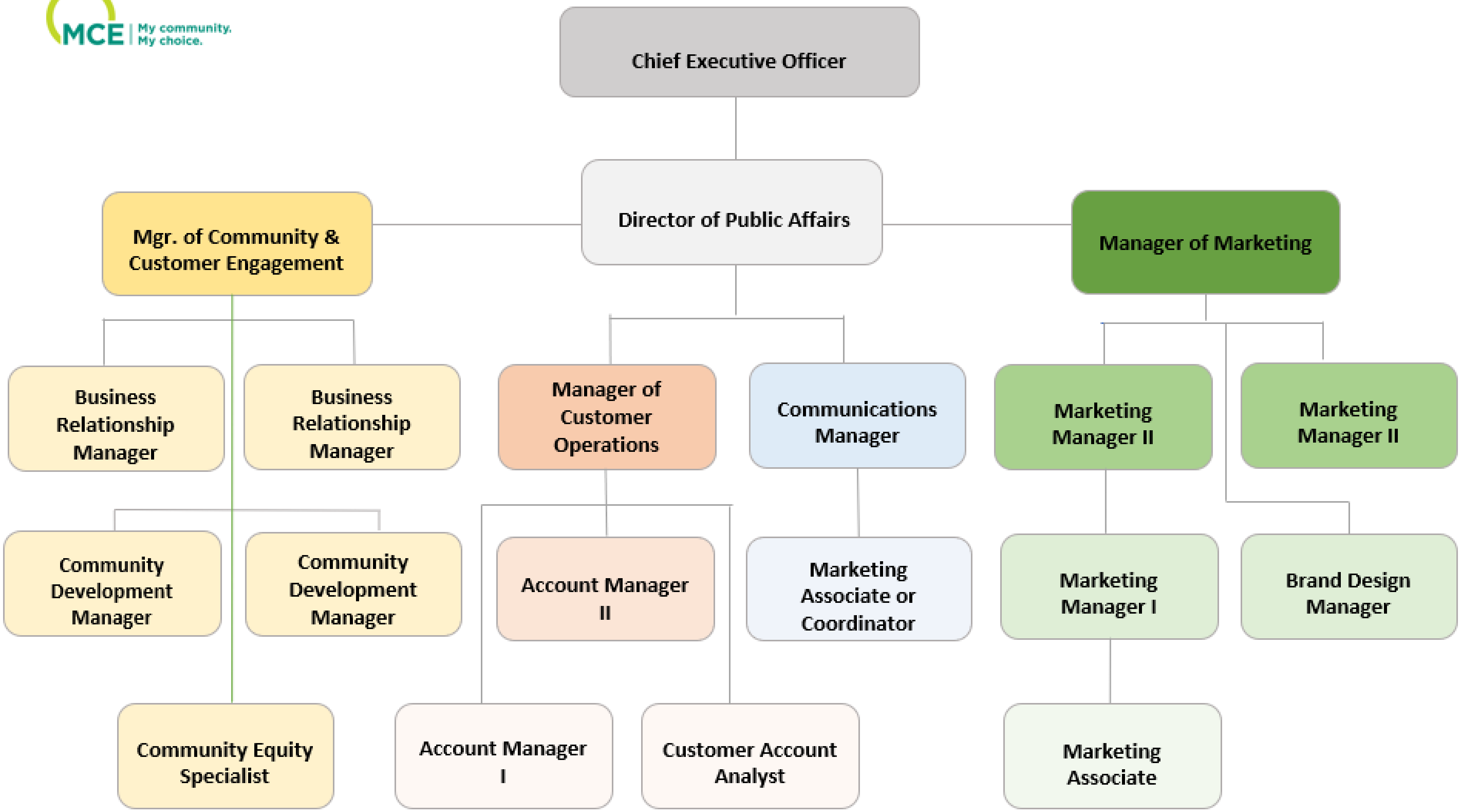
This question is not applicable to MCE.

III. Appendices

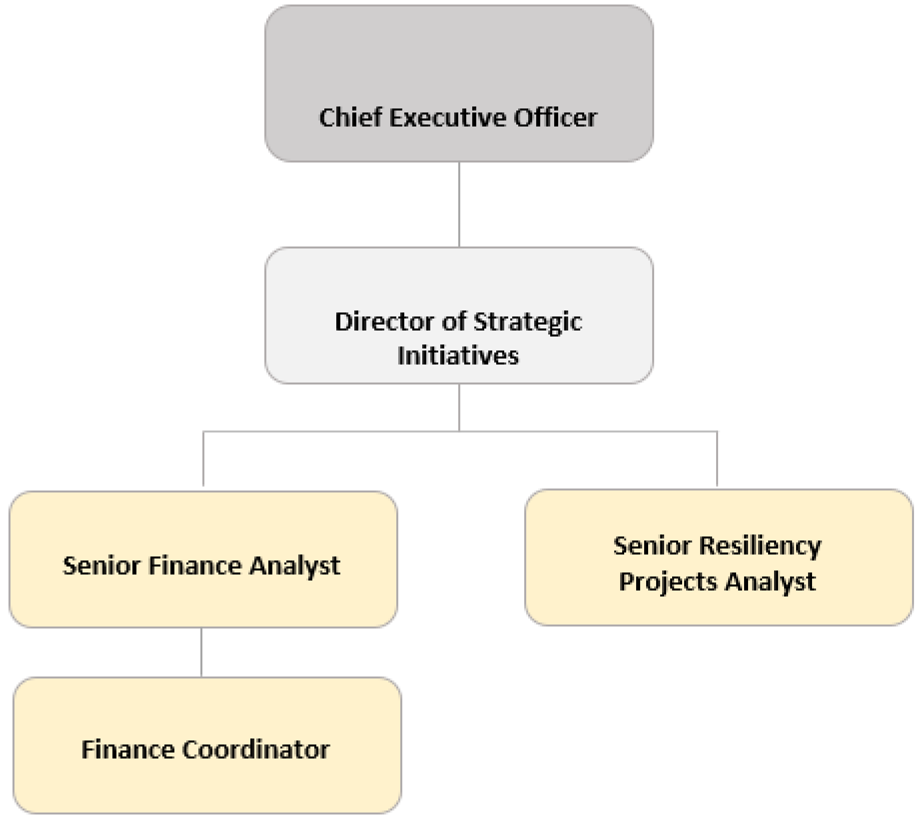
Appendix A: Supporting Information – Request I. A.



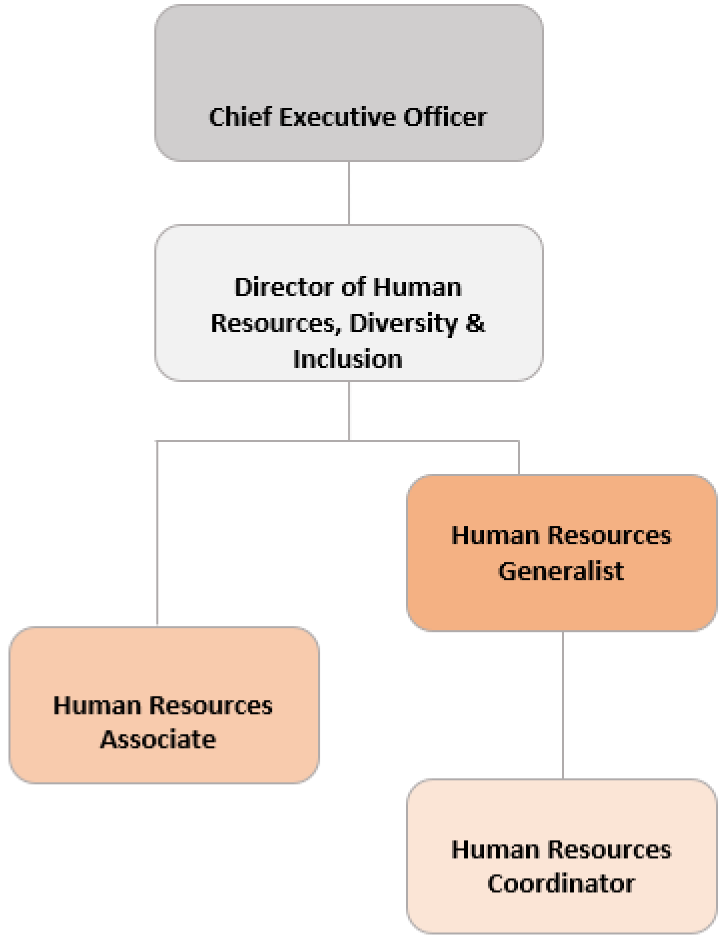

Chief Executive Officer
General Counsel & Director of Policy
Senior Policy Analyst
Senior Policy Counsel
Senior Policy Counsel
Policy Counsel II
Legal Counsel II
Legal Counsel I
Compliance Operations Manager
Regulatory & Legislative Policy Assistant
Legal Assistant I
Regulatory & Legislative Policy
Legal



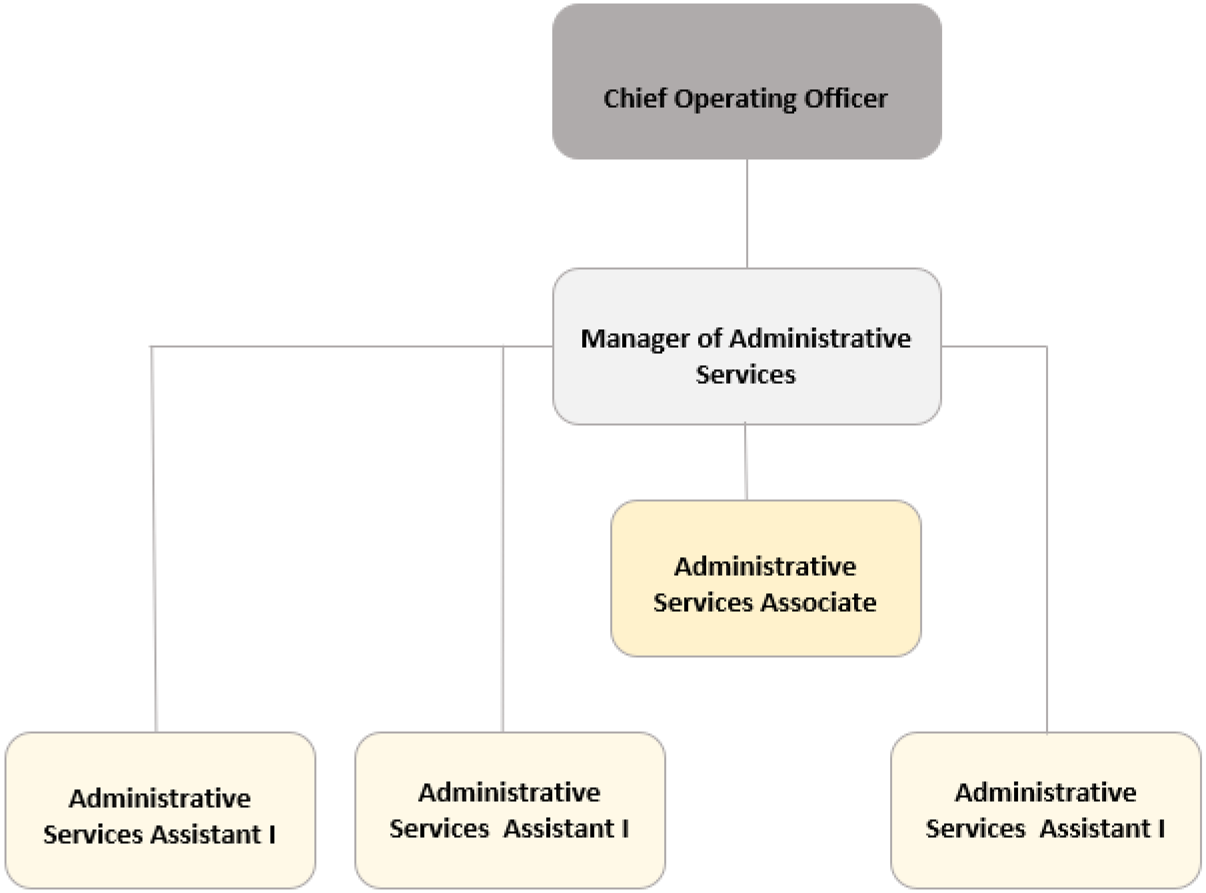
Public Affairs



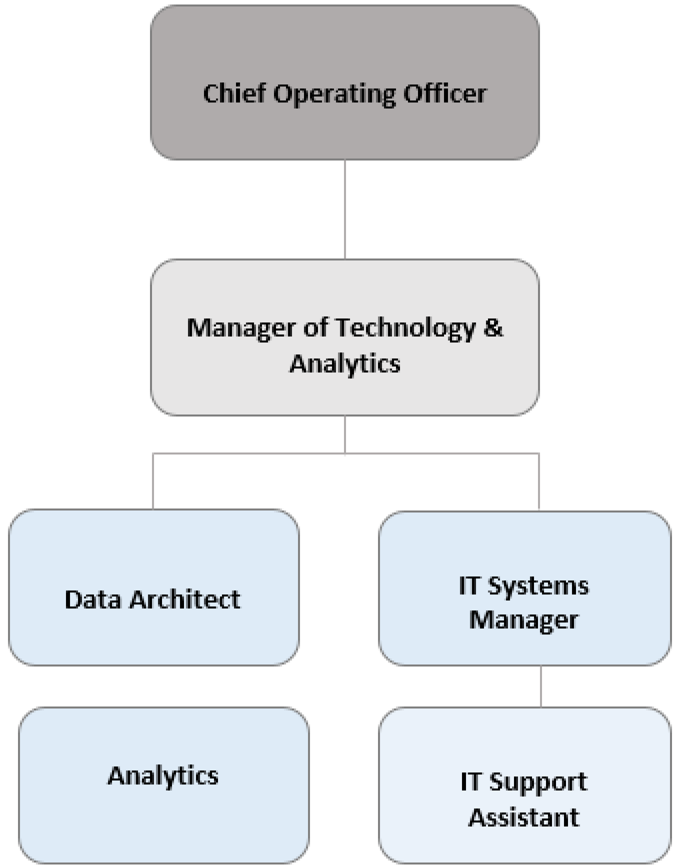
Strategic Initiatives



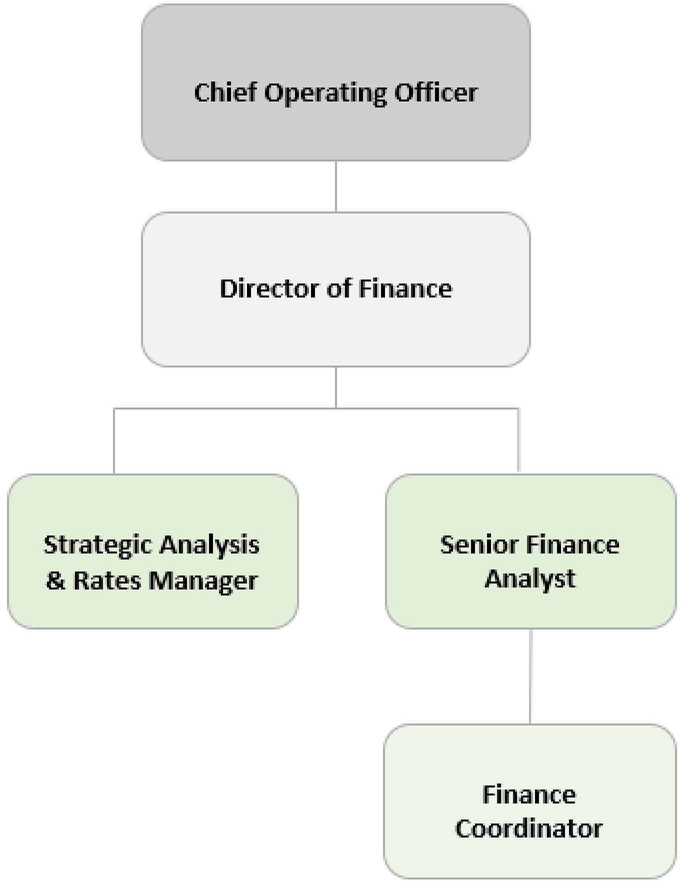
Human Resources



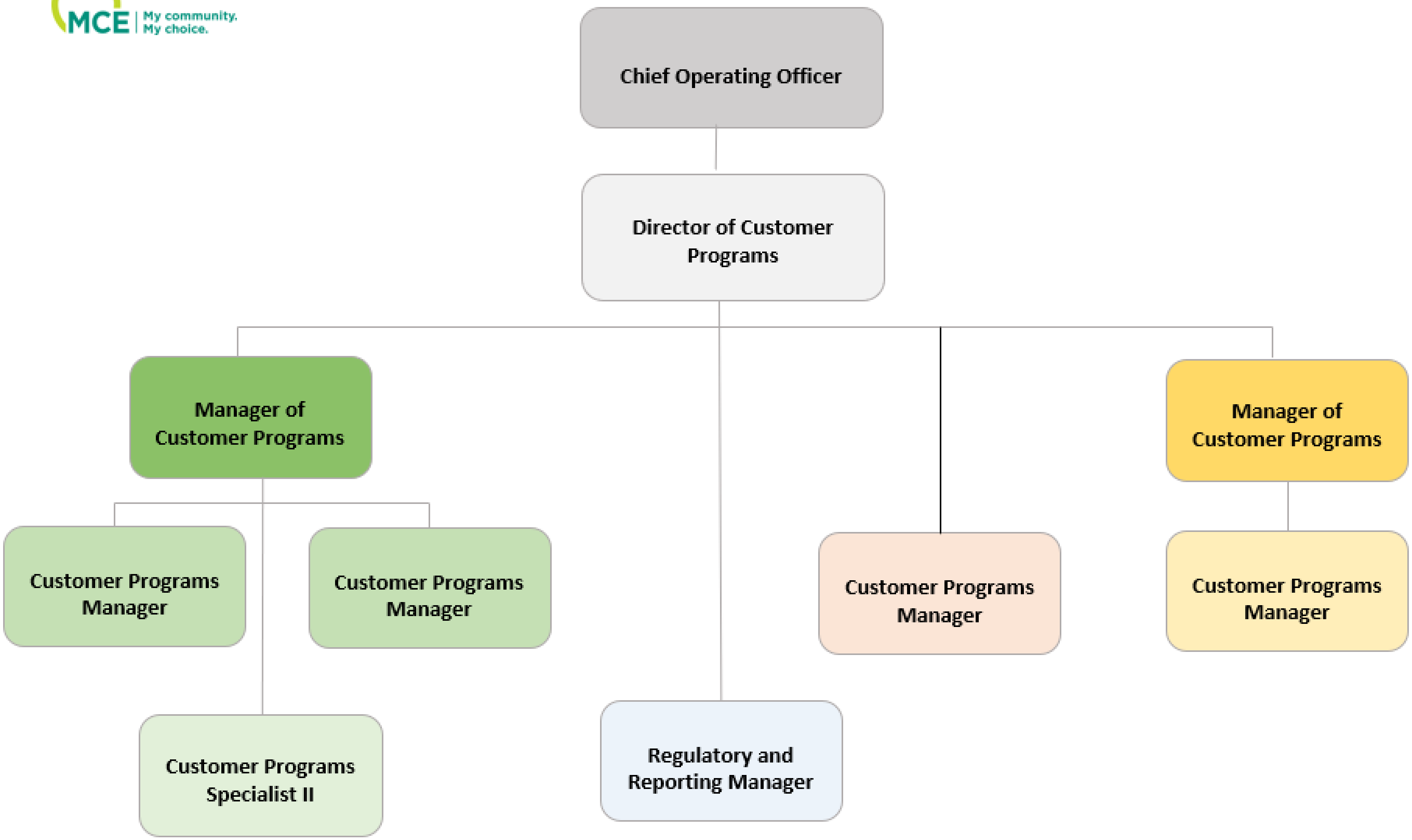
Administrative Services



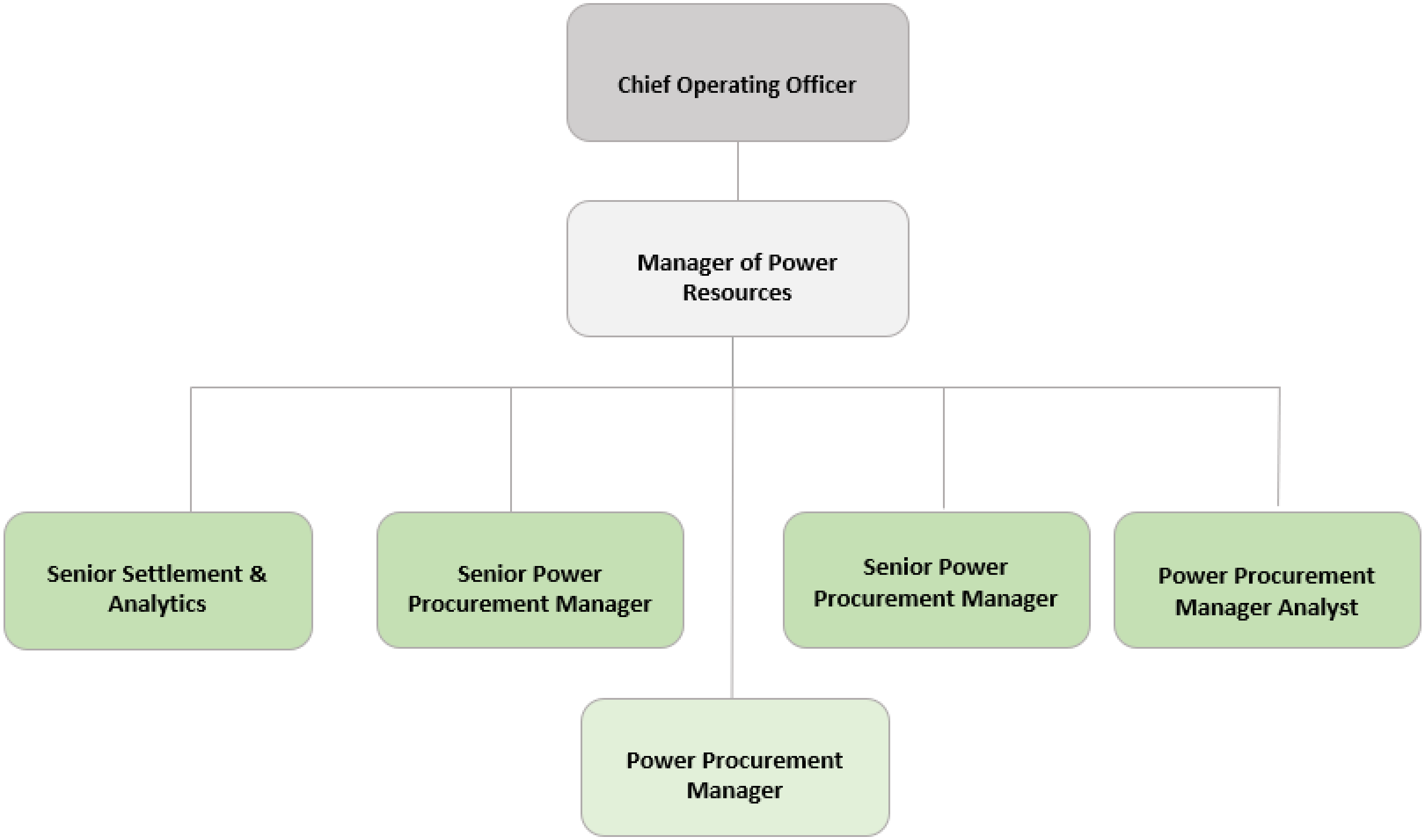
Technology & Analytics


Chief Operating Officer
Director of Finance
Strategic Analysis & Rates Manager
Senior Finance Analyst
Finance Coordinator

Finance



Customer Programs



Power Resources

Appendix B: Supporting Information – Request I.B.

Functional Group	**2018 EE Portfolio FTE**	**2020 EE Portfolio FTE**
Policy, Strategy and Regulatory Reporting Compliance	1.09	1.53
Program Management	1.73	2.43
Engineering Services	-	-
Customer Application/Rebate/Incentive Processing	0.12	0.18
Customer Project Inspections	0.12	0.18
Portfolio Analytics	0.17	0.26
EM&V	0.11	0.14
ME&O	0.25	0.35
Account Management/Sales	-	-
IT	-	-
Call Center	-	-
Total	**3.59**	**5.07**

Aggregated Category	Definition	Functional Category	Detailed Definition
Policy, Strategy, and Regulatory Reporting Compliance	Includes **p**olicy, strategy, compliance, audits and regulatory support	Planning & Compliance	DSM Goal Planning; lead legislative review/positioning; policy support on reg proceedings; portfolio optimization; end use-market strategy; DSM lead for PRP, DRP, ES; locational targeting; audit support; SOX certifications; developing control plans; developing action plans; continuous monitoring; inspections; program/product QA/QC; decision compliance oversight/tracking; data requests; policies & procedures
		Company Regulatory Support	Case management for EE proceedings
Program management	Includes labor, contracts, admin costs for program design, program implementation, product and channel management for all sectors	Program Management & Delivery	
		Product Management	Manage end-to-end new products and services (P&S) intake, evaluation, and launch process; develop and facilitate P&S governance teams, coordination of all sub-process owners, stakeholders, and technical resources required to evaluate and launch new products; evaluate and launch new services and OOR opportunities; develop external partnerships & strategic alliances; work with various companies and associations to help advance standards, products, and tech.; work with external experts to help reduce MCE costs to deliver new prog. and products; develop and launch new customer technologies, products, services for residential and business customers; conduct customer pilots of new technologies and programs; lead customer field demonstrations of new technologies and products; align new P&S to savings programs/incentives; develop new programs/incentives in support of savings goals
		Channel Management	
		Contract Management	Budget forecasting, spend tracking, invoice processing, and contract management with vendors and suppliers; Regulatory support for ME&O activities
Engineering Services	Includes engineering, project management, and contracts associated with workpaper development and pre/post sales project	Custom project support	Management of Emerging Products projects; Customized reviews; LCR/RFO support; Ex-ante review management; Technical policy support; Technical assessments; Workpapers; Tool development; End use subject matter expertise
		Deemed workpapers	

	technical reviews and design assistance	Project management	
Customer Application/Rebate and Incentive Processing	Costs associated with application management and rebate and incentive processing (deemed and custom)	Rebate & Application Processing	
Inspections	Costs associated with project inspections	Inspections	
Portfolio Analytics	Includes analytics support, including internal performance reporting and external reporting	Data analytics	Data development for programs, products and services; Standard and ad hoc data extracts for internal and external clients; Database management; CPUC, CAISO reporting; Data reconciliation; E3 support; Compliance filing support; Funding Oversight; ESPI support; Program Results Data & Performance
EM&V	EM&V expenditures	EM&V Studies	Program and product review; manage evaluation studies
		EM&V Forecasting	EE lead for LTPP and IEPR; market potential study; integration w/ procurement planning; CPUC Demand Analysis Working Group
ME&O	Costs associated with utility EE marketing; no statewide; focus on outsourced portion	Marketing	Customer Programs, Products, and Services Marketing; Digital Product Development; Digital Content & Optimization
		Customer insights	Voice of the Customer; Customer satisfaction study measurement and analysis (JD Power, SDS); Customer testing/research
Account Management / Sales	Costs associated with account rep energy efficiency sales functions	Account Management	
IT	IT project specific costs and regular O&M	IT - project specific	Projects and minor enhancements. Includes project management/business integration ("PMO/BID"). Excluded: maintenance (which SCE defines as when something goes down, normal batch processing, verifying interfaces, etc.).
		IT - regular O&M	

Call Center	Costs associated with call center staff fielding EE program questions	Call Center	
Incentives	Costs of rebate and incentive payments to customers	Incentives	

Appendix C: Supporting Information – Request I.C.

Residential

Sector	Cost Element	Functional Group	2019 EE Portfolio Expenditures ($Million)	2021 EE Portfolio Budget ($Million)
Residential	Labor(1)	Policy, Strategy, and Regulatory Reporting Compliance	$ 0.062	$ 0.080
		Program Management	$ 0.185	$ 0.241
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ 0.031	$ 0.040
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ 0.031	$ 0.040
		ME&O (Local)	$ -	$ -
		Account Management / Sales	$ -	$ -
		IT	$ -	$ -
		Call Center	$ -	$ -
	Labor Total		$ 0.308	$ 0.401
	Non-Labor	Third-Party Implementer (as defined per D.16-08-019, OP 10)		
		Local/Government Partnerships Contracts (3)	$ -	$ -
		Other Contracts	$ -	$ -
		Program Implementation	$ 0.498	$ 0.930
		Policy, Strategy, and Regulatory Reporting Compliance	$ 0.040	$ 0.075
		Program Management	$ 0.125	$ 0.233
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ 0.040	$ 0.075
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ -	$ -
		ME&O (Local)	$ 0.001	$ 0.001
		Account Management / Sales	$ -	$ -
		IT (4)	$ -	$ -
		Call Center	$ -	$ -
		Facilities	$ -	$ -
		Incentives--(PA-implmeneted and Other Contracts Program Implementation) Prog	$ 0.305	$ 1.018
		Incentives--Third Party Program (as defined per D.16-08-019, OP 10)	$ -	$ -
	Non-Labor Total		$ 1.009	$ 2.332
Residential Total			$ 1.317	$ 2.733
	Other (collected through GRC) (2)	Labor Overheads		

Notes:
(1) Labor costs are already loaded with (state loaders covered by EE)
(2) These costs are collected through GRC D.16-06-054
(3) LGP contracts that directly support the sector is included/not included in this item
(4) IT Costs are included in " Policy, Strategy, and Regulatory Reporting Compliance".

Commercial

Sector	Cost Element	Functional Group	2019 EE Portfolio Expenditures ($Million)	2021 EE Portfolio Budget ($Million)
Commercial	Labor(1)	Policy, Strategy, and Regulatory Reporting Compliance	$ 0.019	$ 0.044
		Program Management	$ 0.057	$ 0.132
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ 0.009	$ 0.022
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ 0.009	$ 0.022
		ME&O (Local)	$ -	$ -
		Account Management / Sales	$ -	$ -
		IT	$ -	$ -
		Call Center	$ -	$ -
	Labor Total		$ 0.095	$ 0.221
	Non-Labor	Third-Party Implementers Contracts (as defined per D.16-08-019, OP 10)		
		Local/Government Partnerships Contracts (3)	$ -	$ -
		Other Contracts	$ -	$ -
		Program Implementation	$ 0.236	$ 0.960
		Policy, Strategy, and Regulatory Reporting Compliance	$ 0.010	$ 0.040
		Program Management	$ 0.059	$ 0.240
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ 0.010	$ 0.040
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ -	$ -
		ME&O (Local)	$ 0.000	$ 0.001
		Account Management / Sales	$ -	$ -
		IT (4)	$ -	$ -
		Call Center	$ -	$ -
		Facilities	$ -	$ -
		Incentives--(PA-implmeneted and Other Contracts Program Implementation) Programs	$ 0.234	$ 1.510
		Incentives--Third Party Program (as defined per D.16-08-019, OP 10)	$ -	$ -
	Non-Labor Total		$ 0.549	$ 2.790
Commercial Total (5)			$ 0.643	$ 3.011
	Other (collected through GRC) (2)	Labor Overheads		

Notes:
(1) Labor costs are already loaded with (state loaders covered by EE)
(2) These costs are collected through GRC D.16-06-054
(3) LGP contracts that directly support the sector is included/not included in this item
(4) IT Costs are included in " Policy, Strategy, and Regulatory Reporting Compliance".
(5) Under the previous program categories the following programs were classified as Cross Cutting: 3P-IDEEA, Local-IDSM-ME&O-Local Marketing (EE), SW-IDSM-IDSM. These are included in Table 16 Cross Cutting. These three programs are now classified as Commercial with the elimination of Cross Cutting programs.

Industrial

Sector	Cost Element	Functional Group	2019 EE Portfolio Expenditures ($Million)	2021 EE Portfolio Budget ($Million)
Industrial	Labor(1)	Policy, Strategy, and Regulatory Reporting Compliance	$ 0.011	$ 0.065
		Program Management	$ 0.033	$ 0.195
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ 0.006	$ 0.033
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ 0.006	$ 0.033
		ME&O (Local)	$ -	$ -
		Account Management / Sales	$ -	$ -
		IT	$ -	$ -
		Call Center	$ -	$ -
	Labor Total		$ 0.055	$ 0.326
	Non-Labor	Third-Party Implementers Contracts (as defined per D.16-08-019, OP 10)		
		Local/Government Partnerships Contracts (3)	$ -	$ -
		Other Contracts	$ -	$ -
		Program Implementation	$ 0.040	$ 0.239
		Policy, Strategy, and Regulatory Reporting Compliance	$ 0.004	$ 0.022
		Program Management	$ 0.010	$ 0.060
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ 0.004	$ 0.022
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ -	$ -
		ME&O (Local)	$ 0.000	$ 0.000
		Account Management / Sales	$ -	$ -
		IT (4)	$ -	$ -
		Call Center	$ -	$ -
		Facilities	$ -	$ -
		Incentives--(PA-implmeneted and Other Contracts Program Implementation) Programs	$ -	$ 0.201
		Incentives--Third Party Program (as defined per D.16-08-019, OP 10)	$ -	$ -
	Non-Labor Total		$ 0.058	$ 0.546
Industrial Total			$ 0.113	$ 0.871
	Other (collected through GRC) (2)	Labor Overheads		

Notes:
(1) Labor costs are already loaded with (state loaders covered by EE)
(2) These costs are collected through GRC D.16-06-054
(3) LGP contracts that directly support the sector is included/not included in this item
(4) IT Costs are included in " Policy, Strategy, and Regulatory Reporting Compliance".

Agricultural

Sector	Cost Element	Functional Group	2019 EE Portfolio Expenditures ($Million)	2021 EE Portfolio Budget ($Million)
Agricultural	Labor(1)	Policy, Strategy, and Regulatory Reporting Compliance	$ 0.012	$ 0.038
		Program Management	$ 0.037	$ 0.115
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ 0.006	$ 0.019
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ 0.006	$ 0.019
		ME&O (Local)	$ -	$ -
		Account Management / Sales	$ -	$ -
		IT	$ -	$ -
		Call Center	$ -	$ -
	Labor Total		$ 0.061	$ 0.191
	Non-Labor	Third-Party Implementers Contracts (as defined per D.16-08-019, OP 10)		
		Local/Government Partnerships Contracts (3)	$ -	$ -
		Other Contracts	$ -	$ -
		Program Implementation	$ 0.021	$ 0.067
		Policy, Strategy, and Regulatory Reporting Compliance	$ 0.003	$ 0.009
		Program Management	$ 0.005	$ 0.017
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ 0.003	$ 0.009
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ -	$ -
		ME&O (Local)	$ 0.000	$ 0.000
		Account Management / Sales	$ -	$ -
		IT (4)	$ -	$ -
		Call Center	$ -	$ -
		Facilities	$ -	$ -
		Incentives--(PA-implmeneted and Other Contracts Program Implementation) Programs	$ -	$ 0.175
		Incentives--Third Party Program (as defined per D.16-08-019, OP 10)	$ -	$ -
	Non-Labor Total		$ 0.033	$ 0.277
Agricultural Total			$ 0.094	$ 0.468
	Other (collected through GRC) (2)	Labor Overheads		
Notes:	(1) Labor costs are already loaded with (state loaders covered by EE)			
	(2) These costs are collected through GRC D.16-06-054			
	(3) LGP contracts that directly support the sector is included/not included in this item			
	(4) IT Costs are included in " Policy, Strategy, and Regulatory Reporting Compliance".			

Public Sector

Sector	Cost Element	Functional Group	2019 EE Portfolio Expenditures ($Million)	2021 EE Portfolio Budget ($Million)
Public Sector	Labor(1)	Policy, Strategy, and Regulatory Reporting Compliance		
		Program Management		
		Engineering services		
		Customer Application/Rebate/Incentive Processing		
		Customer Project Inspections		
		Portfolio Analytics		
		ME&O (Local)		
		Account Management / Sales		
		IT		
		Call Center		
	Labor Total			
	Non-Labor	Third-Party Implementers Contracts (as defined per D.16-08-019, OP 10)		
		Local/Government Partnerships Contracts (3)		
		Other Contracts		
		Program Implementation		
		Policy, Strategy, and Regulatory Reporting Compliance		
		Program Management		
		Engineering services		
		Customer Application/Rebate/Incentive Processing		
		Customer Project Inspections		
		Portfolio Analytics		
		ME&O (Local)		
		Account Management / Sales		
		IT (4)		
		Call Center		
		Facilities		
		Incentives--(PA-implmeneted and Other Contracts Program Implementation) Programs		
		Incentives--Third Party Program (as defined per D.16-08-019, OP 10)		
	Non-Labor Total			
Public Sector Total				
	Other (collected through GRC) (2)	Labor Overheads		

Notes:
(1) Labor costs are already loaded with (state loaders covered by EE)
(2) These costs are collected through GRC D.16-06-054
(3) LGP contracts that directly support the sector is included/not included in this item
(4) IT Costs are included in " Policy, Strategy, and Regulatory Reporting Compliance".

Cross Cutting

Sector	Cost Element	Functional Group	2019 EE Portfolio Expenditures ($Million)	2021 EE Portfolio Budget ($Million)
Cross Cutting	Labor(1)	Policy, Strategy, and Regulatory Reporting Compliance	$ -	$ -
		Program Management	$ -	$ 0.072
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ -	$ -
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ -	$ -
		ME&O (Local)	$ -	$ -
		Account Management / Sales	$ -	$ -
		IT	$ -	$ -
		Call Center	$ -	$ -
	Labor Total		$ -	$ 0.072
	Non-Labor	Third-Party Implementers Contracts (as defined per D.16-08-019, OP 10)		
		Local/Government Partnerships Contracts (3)	$ -	$ -
		Other Contracts	$ -	$ -
		Program Implementation	$ -	$ 0.231
		Policy, Strategy, and Regulatory Reporting Compliance	$ -	$ -
		Program Management	$ -	$ 0.058
		Engineering services	$ -	$ -
		Customer Application/Rebate/Incentive Processing	$ -	$ -
		Customer Project Inspections	$ -	$ -
		Portfolio Analytics	$ -	$ -
		ME&O (Local)	$ -	$ -
		Account Management / Sales	$ -	$ -
		IT(4)	$ -	$ -
		Call Center	$ -	$ -
		Facilities	$ -	$ -
		Incentives--(PA-implmeneted and Other Contracts Program Implementation) Progra	$ -	$ -
		Incentives--Third Party Program (as defined per D.16-08-019, OP 10)	$ -	$ -
	Non-Labor Total		$ -	$ 0.289
Cross Cutting Total (5)			$ -	$ 0.361
	Other (collected through GRC) (2)	Labor Overheads		

Notes:
(1) Labor costs are already loaded with (state loaders covered by EE)
(2) These costs are collected through GRC D.16-06-054
(3) LGP contracts that directly support the sector is included/not included in this item
(4) IT Costs are included in " Policy, Strategy, and Regulatory Reporting Compliance".
(5) Under the previous program categories the following programs were classified as Cross Cutting: 3P-IDEEA, Local-IDSM-ME&O-Local Marketing (EE), SW-IDSM-IDSM.
These are included in Table 16 Cross Cutting.
These three programs are now classified as Commercial with the elimination of Cross Cutting programs.

Appendix D: Supporting Information – Response to Scoping Memo, Attachment A, Question C.8.

Energy Savings Targets and Expenditures by Sector

	2019 EE Portfolio Expenditures ($Million)				2021 EE Portfolio Budget ($Million)				2019 EE Portfolio Savings			2021 EE Portfolio Forecasted Savings		
Sector	Labor	Non-Labor (excl. Incentives)	Incentives	Total	Labor	Non-Labor (excl. Incentives)	Incentives	Total	KWH	KW	MMTHERMS	KWH	KW	MMTHERMS
Residential	$ 0.31	$ 0.70	$ 0.31	$ 1.32	$ 0.40	$ 1.31	$ 1.02	$ 2.73	506,753	19	124,124	6,333,145	59	0.06
Commercial	$ 0.09	$ 0.31	$ 0.23	$ 0.64	$ 0.22	$ 1.28	$ 1.51	$ 3.01	1,005,902	211	(6,193)	5,224,085	273	0.09
Agricultural	$ 0.06	$ 0.03	$ -	$ 0.09	$ 0.19	$ 0.10	$ 0.18	$ 0.47	-	-	-	863,147	112	0.01
Industrial	$ 0.06	$ 0.06	$ -	$ 0.11	$ 0.33	$ 0.34	$ 0.20	$ 0.87	-	-	-	1,359,837	33	0.13
Public (GP)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-
Cross Cutting*	$ -	$ -	$ -	$ -	$ 0.07	$ 0.29	$ -	$ 0.36	-	-	-	-	-	-
Total Sector Budget	$ 0.52	$ 1.11	$ 0.54	$ 2.17	$ 1.21	$ 3.33	$ 2.90	$ 7.44	1,512,656	230	117,931	13,780,213	477	0.30
EM&V-PA	$ -	$ -	$ -	$ 0.10		$ -	$ -	$ 0.12	-	-	-	-	-	-
EM&V-ED	$ -	$ -	$ -	$ -		$ -	$ -	0.43	-	-	-	-	-	-
OBF - Loan Pool**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-	-	-	-
EE Total***	0.52	1.11	0.54	2.26	1.21	3.33	2.90	8.00	1,512,656	230	117,931	13,780,213	477	0.30

* Cross Cutting Sector includes Codes & Standards, Emerging Technologies, Workforce Education & Training, OBF admin and 365 IDEA for 2018 only.

** For SDG&E and SCG the loan pool is not part of the authorized EE portoflio budget and is collected and tracked trhough a separate balancing account.

***Rounding Differences

Appendix E: Supporting Information – Response to Scoping Memo, Attachment A, Question C.9.

Energy Efficiency In-House Budget by Sector and Cross-Cutting

	2019 EE Portfolio Expenditures ($Million)				2021 EE Portfolio Budget ($Million)			
Sector	Labor	Non-Labor (excl. Incentives)	Incentives	Total	Labor	Non-Labor (excl. Incentives)	Incentives	Total
Residential	$ 0.31	$ 0.70	$ 0.31	$ 1.32	$ 0.40	$ 1.31	$ 1.02	$ 2.73
Commercial	$ 0.09	$ 0.31	$ 0.23	$ 0.64	$ 0.22	$ 1.28	$ 1.51	$ 3.01
Agricultural	$ 0.06	$ 0.03	$ -	$ 0.09	$ 0.19	$ 0.10	$ 0.18	$ 0.47
Industrial	$ 0.06	$ 0.06	$ -	$ 0.11	$ 0.33	$ 0.34	$ 0.20	$ 0.87
Public (GP)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cross Cutting*	$ -	$ -	$ -	$ -	$ 0.07	$ 0.29	$ -	$ 0.36
Total Sector Budget	$ 0.52	$ 1.11	$ 0.54	$ 2.17	$ 1.21	$ 3.33	$ 2.90	$ 7.44
EM&V-PA	$ -	$ -	$ -	$ 0.10		$ -	$ -	$ 0.12
EM&V-ED	$ -	$ -	$ -	$ -		$ -	$ -	0.43
OBF - Loan Pool**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EE Total***	0.52	1.11	0.54	2.26	1.21	3.33	2.90	8.00

Attachment 2: Marin Clean Energy Program Changes Explanation Tables

2021 Program Level Explanations

PA justification	Third party implementer or Core	Statewide or Local	**Programs to be closed with the disposition of 2021 ABAL**	% change	2019 Claimed TRC	2020 Claimed TRC	2021 Filed TRC	2021 Budget	2020 Budget	Year program started	For existing third party implemented programs, MM/YY Program was due to sunset prior to PY 2021 ABAL planning and new 3P contracting	For existing third party implemented programs, MM/YY Program is extended to as a result of PY 2021 ABAL planning and timing for new 3P contracts' ramp up
MCE decided to end this program in 2019 after the ABAL was filed due to the fact that MCE was not able to secure an updated contract with the existing implementer. Although MCE has a 2020 budget allocated to this program, there will be no expenditures.	x		MCE03 - Single Family Seasonal Savings	-100%	2.12	n/a	This program was not included in MCE's 2021 ABAL	$ -	$ 101,845	2016	12/31/2019	n/a

PA justification	Third party implementer or Core	Statewide	**Programs to be closed upon completion of commitments**	% change	2019 Claimed TRC	2020 Claimed TRC	2021 Filed TRC	2021 Budget	2020 Budget	Year program started	For existing third party implemented programs, MM/YY Program was due to sunset prior to PY 2021 ABAL planning and new 3P contracting	For existing third party implemented programs, MM/YY Program is extended to as a result of PY 2021 ABAL planning and timing for new 3P contracts' ramp up
MCE will end this program in 2020 for several reasons. First, the program overlaps with MCE's existing Multifamily Comprehensive program and other Multifamily Direct Install programs already in the market. Secondly, the program is not cost effective as a result low participation, limited deemed measure offerings due to workpapers expiring, and COVID-19 impacts.	x		MCE05 - Multifamily Direct Install	-100%	0.00	MCE will continue to offer this program until Decemeber 2020 to honor program committments. MCE will provide the claimed TRC in next year's ABAL. As of 2020Q1, this program has a TRC of 0.07.	This program was not included in MCE's 2021 ABAL	$ -	$ 391,064	2019	12/31/2020	n/a

PA justification	Third party implementer or Core	Statewide	**Programs with reduced budgets (>40% budget decrease), to continue in 2021**	% change	2019 Claimed TRC	2020 Claimed TRC	2021 Filed TRC	2021 Budget	2020 Budget	Year program started	For existing third party implemented programs, MM/YY Program was due to sunset prior to PY 2021 ABAL planning and new 3P contracting	For existing third party implemented programs, MM/YY Program is extended to as a result of PY 2021 ABAL planning and timing for new 3P contracts' ramp up
2019 and 2020 were program ramp up years for the Agricultural and Industrial Resource (AIR) program. Additionally, MCE has deployed cost savings strategies while maintaining a cost-effective forecast.	x		MCE10 - Industrial	-59%	0.00	0.00 as of 2020Q1	1.17	$ 871,077	$ 2,125,484	2019	n/a	n/a
2019 and 2020 were program ramp up years for the Agricultural and Industrial Resource (AIR) program. Additionally, MCE has deployed cost savings strategies while maintaining a cost-effective forecast.	x		MCE11 - Agricultural	-32%	0.00	0.00 as of 2020Q1	1.12	$ 468,195	$ 687,463	2019	n/a	n/a

PA justification	Third party implementer or Core	Statewide	**Programs with enhanced budgets (>40% budget increase)**	% change	2019 Claimed TRC	2020 Claimed TRC	2021 Filed TRC	2021 Budget	2020 Budget	Year program started	For existing third party implemented programs, MM/YY Program was due to sunset prior to PY 2021 ABAL planning and new 3P contracting, or mark "NEW 3P" program if program is result of 3P solicitation process per D1801004	For existing third party implemented programs, MM/YY Program is extended to as a result of PY 2021 ABAL planning and timing for new 3P contracts ramp up , or mark "NEW 3P" program if program is result of 3P solicitation process per D1801004.
MCE expects an expansion of the Commercial Upgrade Program in 2021, primarily rooted in the development of population-level NMEC portfolios and expected completion of large commercial SEM projects enrolled in 2019 and 2020. Lastly, MCE is adding a new implementer.	x		MCE02 - Commercial	104%	0.48	0.32 as of 2020 Q1	1.33	$ 3,010,541	$ 1,477,001	2016	n/a	n/a
With the discontinued Multifamily Direct Install program and new direct install measures available to implement in 2021, MCE is doubling down on it SF Residential Direct Install program.	x		MCE08 - Single Family Direct Install	124%	0.09	0.19 as of 2020Q1	0.31	$ 1,577,832	$ 704,976	2019	n/a	n/a

PA justification	Third party implementer or Core	Statewide	**Programs that are new in 2021**	% change	2019 Claimed TRC	2020 Claimed TRC	2021 Filed TRC	2021 Budget	2020 Budget	MM/YY program to start	MM/YY Program is due to sunset; and flag as "NEW 3P" program if program is result of 3P solicitation process per D1801004	For existing third party implemented programs, MM/YY Program is extended to as a result of PY 2021 ABAL planning and timing for new 3P contracts ramp up , or mark "NEW 3P" program if program is result of 3P solicitation process per D1801004
			MCE is not proposing any new programs for 2021.					$ -	$ -			

Attachment 3: Marin Clean Energy Budget and Savings True-up Tables

	Annual Rolling Portfolio Budget Forecast - True-up								
Sector	2018**	2019	2020	2021	2022	2023	2024	2025	**Total**
Residential	$ 558,107	$ 1,317,213	$ 2,163,109	$ 2,733,236	$ 6,170,017	$ 6,170,017	$ 6,170,017	$ 5,660,017	$ 30,941,731
Commercial	$ 617,207	$ 643,277	$ 1,477,001	$ 3,010,541	$ 2,934,922	$ 2,934,922	$ 2,934,922	$ 3,251,922	$ 17,804,713
Industrial	$ 137,360	$ 113,244	$ 2,125,484	$ 871,077	$ 1,269,596	$ 1,269,596	$ 1,269,596	$ 1,260,596	$ 8,316,550
Agriculture	$ -	$ 93,618	$ 687,463	$ 468,195	$ 1,181,259	$ 1,181,259	$ 1,181,259	$ 1,260,259	$ 6,053,310
Emerging Tech	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Public	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Codes and Standards	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WE&T	$ -	$ -	$ 346,667	$ 361,481	$ 346,667	$ 346,667	$ 346,667	$ 346,667	$ 2,094,815
Finance	$ 18,524	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,524
OBF Loan Pool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	$ 1,331,198	$ 2,167,352	$ 6,799,724	$ 7,444,530	$ 11,902,460	$ 11,902,460	$ 11,902,460	$ 11,779,460	$ 65,229,642
EM&V	$ 16,590	$ 95,351	$ 108,795	$ 119,113	$ 189,405	$ 189,405	$ 189,405	$ 187,405	$ 1,095,469
Total Portfolio Program Year PA Budget	$ 1,347,788	$ 2,262,703	$ 6,908,519	$ 7,563,643	$ 12,091,865	$ 12,091,865	$ 12,091,865	$ 11,966,865	$ 66,325,111
Total Authorized Portfolio PY Budget Cap	$ 8,532,000	$ 8,532,000	$ 12,404,000	$ 12,404,000	$ 10,998,000	$ 10,998,000	$ 10,998,000	$ 10,870,000	$ 85,736,000

***2018 - 2019 are actual expenditures. 2020 - 2025 are forecasted expenditures.**

**** "Reset" 2018 budget at or below 2018 annual budget approved in Business plan Decision. "True-up" years 2019-2025.**

Sector	2018	2019	2020	2021	2022	2023	2024	2025
			Annual Rolling Portfolio Savings Forecast - True-up (kWh)					
Residential	336,227	506,753	2,850,292	2,850,292	2,797,634	2,797,634	2,797,634	2,797,634
Commercial	823,364	1,005,902	3,641,084	3,641,084	4,246,583	4,246,583	4,246,583	4,246,583
Industrial	n/a	-	1,179,161	1,179,161	1,864,651	1,864,651	1,864,651	1,864,651
Agriculture	n/a	-	709,938	709,938	659,030	659,030	659,030	659,030
Emerging Tech	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Public	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Codes and Standards	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
WE&T	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Finance	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
OBF Loan Pool	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Actual Portfolio Savings	1,161,609	1,514,674	n/a	n/a	n/a	n/a	n/a	n/a
Total Forecast Portfolio Savings	1,846,947	1,846,947	8,380,475	8,380,475	9,567,898	9,567,898	9,567,898	9,567,898
CPUC Goal*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
% of Goal*	63%	82%	n/a	n/a	n/a	n/a	n/a	n/a

***2018 - 2019 are actual savings. 2020 - 2025 are forecasted savings.**

Annual Rolling Portfolio Savings Forecast - True-up (kW)

Sector	2018	2019	2020	2021	2022	2023	2024	2025
Residential	27	19	246	246	236	236	236	236
Commercial	126	211	116	116	81	81	81	81
Industrial	n/a	-	38	38	59	59	59	59
Agriculture	n/a	-	84	84	78	78	78	78
Emerging Tech	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Public	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Codes and Standards	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
WE&T	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Finance	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
OBF Loan Pool	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Actual Portfolio Savings	153	230	n/a	n/a	n/a	n/a	n/a	n/a
Total Forecast Portfolio Savings	349	696	484	484	454	454	454	454
CPUC Goal*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
% of Goal*	44%	33%	n/a	n/a	n/a	n/a	n/a	n/a

***2018 - 2019 are actual savings. 2020 - 2025 are forecasted savings.**

Annual Rolling Portfolio Savings Forecast - True-up (therms)

Sector	2018	2019	2020	2021	2022	2023	2024	2025
Residential	0.07	0.12	0.41	0.41	0.45	0.45	0.45	0.45
Commercial	(0.00)	(0.00)	0.01	0.01	0.01	0.01	0.01	0.01
Industrial	n/a	-	0.12	0.12	0.14	0.14	0.14	0.14
Agriculture	n/a	-	0.01	0.01	0.01	0.01	0.01	0.01
Emerging Tech	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Public	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Codes and Standards	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
WE&T	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Finance	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
OBF Loan Pool	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Actual Portfolio Savings	0.07	0.12	n/a	n/a	n/a	n/a	n/a	n/a
Total Forecast Portfolio Savings	0.10	0.40	0.55	0.55	0.61	0.61	0.61	0.61
CPUC Goal*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
% of Goal*	70%	30%	n/a	n/a	n/a	n/a	n/a	n/a

***2018 - 2019 are actual savings. 2020 - 2025 are forecasted savings.**

Attachment 4: Marin Clean Energy CEDARS Filing Submission Receipt

CEDARS FILING SUBMISSION RECEIPT

The MCE portfolio filing has been submitted and is now under review. A summary of the filing is provided below.

PA: Marin Clean Energy (MCE)

Filing Year: 2021

Submitted: 19:23:11 on 31 Aug 2020

By: Qua Vallery

Advice Letter Number: 45-E

* Portfolio Filing Summary *

- TRC: 1.0799
- PAC: 1.1675
- TRC (no admin): 2.5791
- PAC (no admin): 3.1424
- RIM: 1.1675
- Budget: $7,563,642.69

* Programs Included in the Filing *

- MCE01: Multi-Family
- MCE02: Commercial Upgrade
- MCE07: Single Family Comprehensive
- MCE08: Single Family Direct Install Standalone
- MCE10: Industrial
- MCE11: Agricultural
- MCE16: Workforce Education and Training (WET)
- MCE98: MCE EM&V;

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

COMMENTS OF MARIN CLEAN ENERGY AND THE BAY AREA REGIONAL ENERGY NETWORK REGARDING NATURAL RESOURCES DEFENSE COUNCIL MOTION

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September 1, 2020

I. INTRODUCTION

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE")[1] and the Association of Bay Area Governments ("ABAG"), on behalf of the San Francisco Bay Area Regional Energy Network ("BayREN"),[2] submit these joint comments in response to the Administrative Law Judge's Ruling Seeking Comments Regarding Natural Resources Defense Council Motion ("NRDC Motion") filed July 31, 2020 ("July 31 Ruling").[3] The July 31 Ruling invites parties to comment in response to the April 24, 2020 motion filed by NRDC[4] putting forward the California Energy Efficiency Coordinating Committee ("CAEECC") Proposal for Improvements to the EE Portfolio and Budget Approval and Implementation Process ("CAEECC Proposal").[5] Administrative Law Judge Kao invites comment in particular on an enumerated list of twenty-two questions about the NRDC Motion and the attached CAEECC Proposal. MCE and BayREN address many of these questions below.

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[1] MCE, California's first CCA, is a not-for-profit public agency that began service in 2010 with the goals of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs. MCE is a load-serving entity serving approximately 1,000 MW peak load, providing electricity generation services to more than 1.1 million people in 34 communities across Marin, Contra Costa, Napa and Solano counties.

[2] BayREN is a collaboration of the nine counties that make up the Bay Area. Led by ABAG, BayREN implements effective energy savings programs on a regional level and draws on the expertise, experience and proven track record of San Francisco Bay Area local governments to develop and administer successful climate, resource and sustainability programs.

[3] Administrative Law Judge's Ruling Seeking Comments Regarding Natural Resources Defense Council Motion in R.13-11-005, filed July 31, 2020 (hereinafter "July 31 Ruling").

[4] The Natural Resource Defense Council's Motion Seeking Commission Ruling and Comment Period on the California Energy Efficiency Coordinating Committee Proposal for Improvements to the Energy Efficiency Portfolio and Budget Approval Process Working Group Report in R.13-11-005, filed April 24, 2020 (hereinafter "NRDC Motion").

[5] The CAEECC Proposal was developed through the collaborative efforts of the CAEECC-hosted Energy Efficiency Portfolio Filing Processes Working Group, of which NRDC, MCE, and BayREN are all members.

MCE and BayREN are generally supportive of the NRDC Motion and CAEECC Proposal and offer these joint comments to help clarify, expand, and build off of that proposal. Adopting the CAEECC Proposal to move to a four-year program cycle with Annual Reports would provide benefits including increased certainty, enhanced accountability, and the means to better support multi-year programs. However, MCE and BayREN would also support modifications to the current Rolling Portfolio cycle process that would achieve similar goals without requiring a significant departure from the current process. For instance, MCE and BayREN also believe that the alternative to move to biennial budget advice letters as described in Question 4 of the July 31 Ruling would achieve many, though not all, of the same goals set out by the CAEECC Proposal and would thus be acceptable if accompanied by additional reforms as discussed in these comments.

II. BACKGROUND

MCE and BayREN are both program administrators ("PAs") of ratepayer-funded energy efficiency ("EE") programs under the current rolling portfolio cycle. MCE has been administering EE funds under California Public Utilities Code ("Code") Section 381.1(a)-(d) since 2013.[6] The Commission originally restricted MCE's EE programs to serving gaps in Investor Owned Utility ("IOU") programs and hard-to-reach markets.[7] On January 17, 2017, MCE filed a Business Plan with the Commission that requested authorization to expand MCE's EE portfolio to include additional sectors and programmatic offerings, including Residential;

[6] To date, MCE is the only community choice aggregator ("CCA") to have requested energy efficiency funding under Code Section 381.1(a)-(d).
[7] *See* D.12-11-015 at 45-46 in Application ("A".)12-07-001, issued Nov. 15, 2012.

Commercial; Industrial; Agricultural; and Workforce Education and Training ("WE&T") programs.[8] On June 5, 2018, the Commission approved MCE's Business Plan in D.18-05-041.[9]

BayREN, initially approved to offer certain EE programs in D.12-11-015,[10] has since its inception designed and implemented programs pursuant to the Regional Area Networks ("REN") directives of filling gaps in the market, developing programs for hard-to-reach markets, and piloting new approaches to programs that may have the ability to scale and offer innovative avenues to energy savings.[11] Initially approved as a pilot,[12] BayREN became a permanent PA in D.19-12-021.[13] Unlike MCE and the IOUs, the RENs are not held to a specific cost-effectiveness threshold due to the small size of the REN portfolios and because "RENs are inherently designed to take on filling gaps in the other larger portfolios or serving the needs of hard-to-reach customer segments/markets that will be naturally less cost-effective to serve."[14]

III. COMMENTS ON SUBJECTS ENUMERATED IN THE RULING

MCE and BayREN appreciate the invitation in the July 31 Ruling to comment on various subjects. We jointly address the subjects enumerated in the ruling in the comments below.

Cycle length and budget authorizations

1. What are the major challenges or benefits associated with the current Rolling Portfolio cycle length and budget authorization structure?

MCE and BayREN observe that benefits of the current Rolling Portfolio cycle include the elimination of funding "cliffs" where program funding halts due to gaps between program

[8] *See* Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan in A.17-01-017, filed January 17, 2017.
[9] *See* D.18-05-041, Ordering Paragraph 33 at 189 in A.17-01-013, issued June 5, 2018.
[10] D.12-11-015 at 35-43.
[11] *See id.*
[12] D.12-11-015 at 35-42.
[13] D.19-12-021 at 16-17 in R.12-11-005, issued Dec. 12, 2019.
[14] *Id.* at 37.

cycles. Such abrupt breaks in funding can cause market instability, particularly with respect to the EE workforce. The interest in avoiding such funding gaps and market instability was one of the primary factors in the development of the current Rolling Portfolio structure, under which PAs were to be provided with continuous funding over a ten-year period.

Despite the intended benefits of the Rolling Portfolio, MCE and BayREN agree that, as the CAECC Proposal suggests, the Rolling Portfolio Business Plan is strong in concept but in application has a number of challenges.[15] One issue is that an application covering a ten-year period of authorized funding must necessarily contain limited information, as forecasting ten years into the future is inherently difficult. As a result, the ten-year business plan application provides limited opportunities for review of the details of forecasted budgets, savings, cost-effectiveness, and other Commission-approved savings targets and non-energy related metrics specific to each PA.

In order to mitigate the limitations on the level of detail that can be contained in a ten-year business plan application, the PAs currently file an Annual Budget Advice Letter ("ABAL") to enable additional reporting and accountability. However, the scope of the required ABAL is quite broad. In Decision 15-10-028, the Commission articulated the purpose of the ABALs, and the corresponding review, within the new Rolling Portfolio process: "[T]he annual budget filings and their associated review should be relatively ministerial. The question for Commission Staff in reviewing a budget advice letter should be 'does this conform to the approved business plan?'"[16] Accordingly, the ABALs were not designed in the first instance to create a forum for debating the merits of program design or implementation. However, in practice, the Rolling

[15] *See* NRDC Motion, Attachment A, CAEECC Proposal at 4, Section 2.0 (hereinafter "CAEECC Proposal").
[16] D.15-10-028 at 62. *See also* D.18-05-041 at 59.

Portfolio process has led to precisely this type of debate. This level of programmatic annual review can be challenging for Energy Division to complete in an expeditious manner and can lead to uncertainty for PAs, the EE workforce, and customers.

2. **If you perceive challenges with the current cycle length and budget authorization structure, do you agree that the proposal in the NRDC motion remedies those challenges? Why or why not?**

MCE and BayREN generally support the NRDC Motion and attached CAEECC Proposal. However, the alternative described by the July 31 Ruling in Question 4, which would incrementally modify the current Rolling Portfolio process to require biennial advice letters in place of ABALs, would achieve many of the same goals without wholesale changes to the current process. The CAEECC Proposal advocates moving to a four-year programming cycle with Annual Reports that better reflect multi-year goals and are less resource intensive than ABALs. This would be an advantageous change, facilitating more efficient multi-year contracting with program implementers and providing financing certainty. However, the alternative to maintaining the Rolling Portfolio cycle while eliminating ABALs and moving to biennial Tier 2 advice letters would also better support multi-year programming. This option would similarly provide enhanced certainty, enable multi-year contracts, and support long-term program goals. For these reasons, MCE and BayREN support either alternative.

However, MCE and BayREN also note that either alternative would require certain modifications. As described below in these comments, MCE and BayREN propose a number of changes to the details of the CAEECC Proposal, including the threshold for requiring remedial filings, which should allow for year-to-year fluctuations. At the same time, we support many of the other changes proposed in the CAEECC Proposal that are designed to improve processes and align technical inputs. If the Commission were to choose to continue the Rolling Portfolio process with a biennial Tier 2 advice letter requirement in place of the ABAL requirement, those other elements of the CAEECC Proposal should also be incorporated into the decision. This includes aligning technical inputs such as cost-effectiveness data to better support multi-year EE programming should also be incorporated into the decision. MCE and BayREN address these issues in greater detail below.

3. **One of the objectives of the current 10-year budget authorization was to provide long-term funding certainty for the energy efficiency programs and to support long-term planning activities by the California Energy Commission and the California Independent System Operator. Do you believe that shortening the budget authorization cycle may negatively impact these objectives? Why or why not?**

MCE and BayREN do not anticipate that shortening the budget authorization cycle would have a negative impact on the stated Commission objectives. While the total portfolio budget is currently approved for ten years, the specific funding level of a PA's portfolio is approved annually in the ABALs and is impacted by a number of factors, including changes to engineering values and avoided cost updates. For this reason, the current ten-year authorization process does not result in sufficient certainty to fully support long-term planning activities, nor does it allow for multi-year contracts with implementers given funding levels are in reality only guaranteed for one year. Ultimately, the PA lacks certainty that over a ten-year period the full budget put forward in the Business Plan will be allocated. The proposed changes would extend that funding certainty to four years, enabling more successful long-term programming and true multi-year contracts to support EE markets and the EE workforce.

Furthermore, the CAEECC Proposal filed with the NRDC Motion indicates that in the absence of timely Commission action, program funding levels would continue by default at existing levels until the Commission takes action regarding the next program cycle. The CAEECC Proposal states:[17]

> One concern among some stakeholders with the previous three-year cycle was the potential for funding cliffs at the end of the application cycle. To help mitigate this situation, consistent with existing policy, if there is a delay in regulatory approval of the subsequent application cycle, the PA would continue to implement their programs with the current approved budgets at the average yearly budget of the currently approved four-year cycle until such time as the CPUC decides on the application.

Therefore, the CAECC Proposal will not lead to additional funding uncertainty. For these reasons, shortening the budget authorization cycle will not have a negative impact.

4. **Instead of the proposal in the NRDC motion, would more incremental modifications to the current Rolling Portfolio better address identified challenges with the current structure? For instance, would replacing annual budget advice letters, with Tier 2 budget advice letters submitted every two years aligned with biennial goal updates, resolve current challenges identified with the Rolling Portfolio process? Why or why not?**

MCE and BayREN would support either alternative: (1) modifying the current Rolling Portfolio cycle to replace ABALs with biennial advice letters, or (2) adopting the four-year cycle described in the CAECC Proposal attached to the NRDC Motion, with modifications as described in these comments. Both of these options offer pathways for change that would help to address issues in the current EE procedures. However, MCE and BayREN note that the CAECC Proposal makes a number of recommendations beyond switching from a ten-year cycle with annual ABALs to a four-year cycle with Annual Reports. MCE and BayREN urge the Commission to also carefully consider the other recommendations contained in the proposal,

[17] CAEECC Proposal at 9.

including improvements to the alignment of technical inputs and other concerns described in these comments in response to other questions, including Question 9 below.

Regarding the option of replacing ABALs with Tier 2 advice letters filed every two years, we believe this would represent a positive change. Currently, the ABALs filed by the PAs are cumbersome both to prepare and to review. This annual process could become biennial with minimal impact to Energy Division's ability to provide oversight. Moving to a biennial Tier 2 advice letter would be beneficial to PAs, stakeholders, and Energy Division.

In addition to structural and procedural changes, the July 3, 2020 Assigned Commissioner and Administrative Law Judges' Amended Scoping Ruling Addressing Impacts of COVID-19 ("July 3 Scoping Ruling")[18] also raises a number of policy concerns. Whereas structural changes, such as switching from an ABAL to a biennial advice letter may be implemented more rapidly in the near-term, the substantive policy issues that need to be addressed in this proceeding require additional time and consideration. Important policy issues that should have further consideration over a longer timeframe include: (1) the cost-effectiveness framework and requirements, and (2) reassessment of the Potential and Goals methodology, including interactions between the integrated resource planning process and the energy efficiency goal-setting process.

These policy issues are important to resolve. Until adequate time has been given to consider these issues and the Commission renders a decision, there will not be a meaningful benefit in requiring the PAs to re-file their business plans. Business plan filings are very time-intensive and costly for the PAs to prepare, at ratepayer expense, and are particularly challenging

[18] *See* Assigned Commissioner and Administrative Law Judges' Amended Scoping Ruling Addressing Impacts of COVID-19 in R. 13-11-005, filed July 3, 2020 (hereinafter "Scoping Ruling").

for smaller PAs like MCE and BayREN that have limited staffing resources. MCE and BayREN address this issue in greater detail in response to Question 14 below.

<u>Savings goals for investor-owned utilities (IOUs) and targets for non-IOU program administrators</u>

5. **What is the appropriate oversight role of Commission staff during energy efficiency program implementation (i.e., mid-cycle between CPUC budget authorization points)? Does the proposal in the NRDC motion ensure this level of oversight? Please support your answer.**

MCE and BayREN generally support the CAECC Proposal on this subject, which proposes that Annual Reports be filed as Tier 1 advice letters unless major remediation and modification is required. The annual Tier 1 advice letter process would provide updated tracking of metrics as well as details concerning program developments within the year and updated cumulative accomplishments over the course of the four-years. This process, together with the data and metrics made available through CEDARS, would ensure accountability to Commission staff and stakeholders towards the PAs progress toward program goals. As described in the CAEECC Proposal, each PA will post its Annual Report on the CAEECC website and will provide semi-annual updates on progress toward approved goals and objectives to the CAEECC.[19]

In addition to tracking developments within the year and reporting on cumulative accomplishments, under the proposal, Annual Reports would include a description of future plans to meet or exceed the cumulative Commission-approved four-year goals. While it is difficult to measure progress toward four-year goals with specificity when looking at a twelve-month window in time, the proposed narrative description would give the PA an additional opportunity to describe and report on the implementation of its programs on a longer timescale,

[19] CAEECC Proposal at 7.

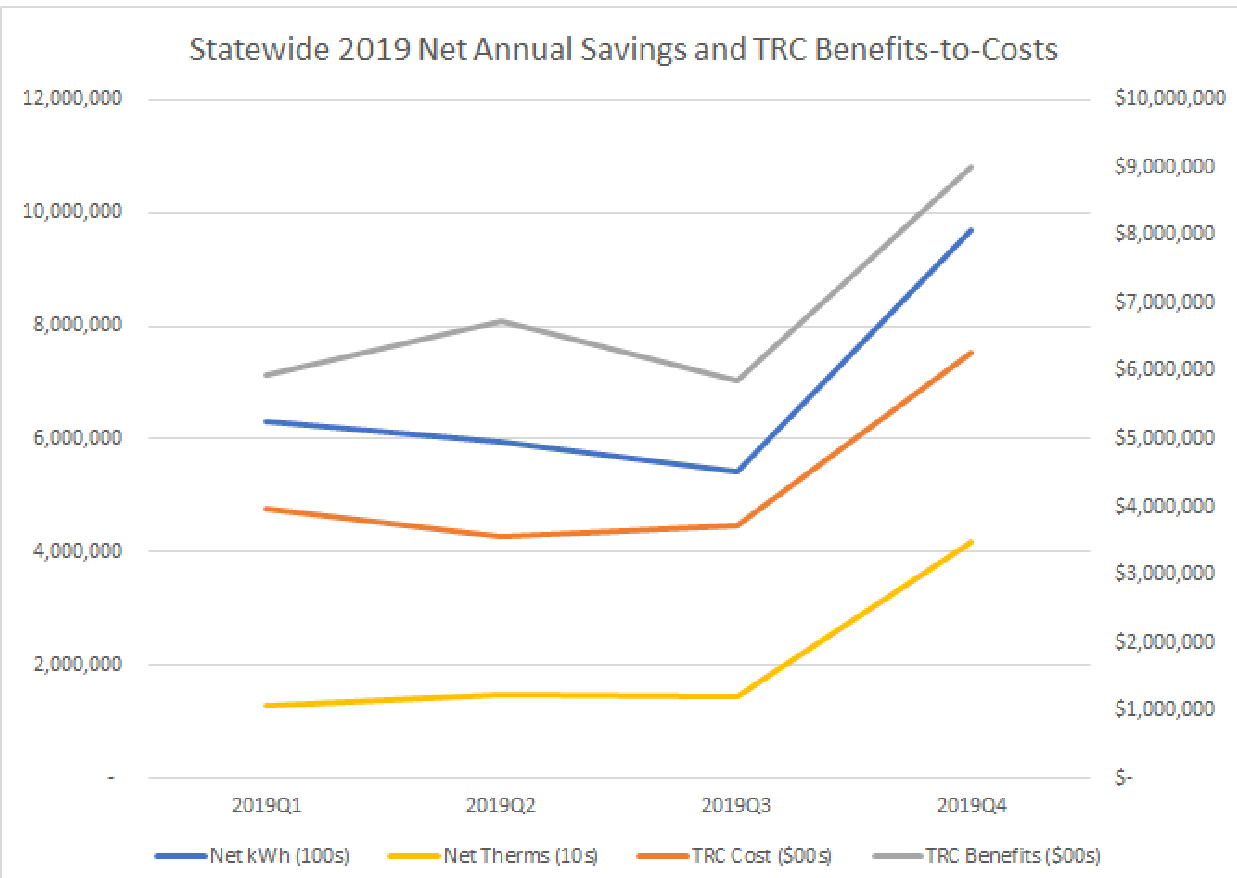
as well as progress toward achieving its overall goals. Minor developments and modest adjustments to implementation and program development could be reported by the PAs in the Annual Report without the need for a more lengthy or formal in-cycle review. To the extent a need for special remediation arises due to major programmatic changes, MCE and BayREN support the concept of filing mid-cycle modifications when necessary as a trigger-based Tier 2 advice letter.

6. **Do you agree that a program administrator is not "on-target" if they are not reasonably able to meet their savings goals by 20 percent and cost-effectiveness target by 10 percent, or would you propose different thresholds to determine whether a program administrator is "on-target?" Please explain your recommendation.**

MCE and BayREN support a 20% margin of difference threshold for both savings goals and cost-effectiveness. Below that margin, PAs should be permitted discretion to measure progress against goals and to raise relevant concerns as needed. PAs should be responsible for indicating whether they are on-target to meet established goals by the end of the funding cycle, to the extent they do not exceed the 20% margin of difference.

While MCE and BayREN acknowledge the need to determine some sort of mechanism to ensure that PAs are reasonably expected to meet savings and cost-effectiveness targets, both quarterly status updates and annual filings can fail to provide an accurate reflection of progress toward goals that are longer-term in nature. This applies to cost-effectiveness in the same way that it applies to savings goals. For instance, a long-term program may require a substantial initial financial outlay that results in poor cost-effectiveness at the outset of the program. Ultimately, once initial investments have been completed and the program is in operation for a period of time, the program can still reach its cost-effectiveness goals. However, to the extent programs are evaluated quarterly or annually, this might not be apparent because benefits will not yet have been realized.

This principle is illustrated in the chart below, which shows statewide net annual savings and cost-effectiveness trends over the program year 2019. As is apparent, there is a trend that rises sharply in Quarter 4, in a hockey-stick type pattern. Indeed, about 35% of kWh and 50% of therms savings were claimed in Quarter 4 for the entire statewide EE portfolio. MCE and BayREN believe that, based on precedent, a similar trend line is likely to be seen over a four-year program cycle, with a sharp rise toward the end of that cycle.



Due to the nature of how net energy savings, benefits, and costs accrue over time, PAs may not be able to meet savings and cost-effectiveness goals within even a 20% band, much less a 10% band, until year three of any long-term program. Multi-year budgets recognize that stop/start funding is not in the interests of effective program implementation. A snapshot of program performance on a quarterly basis is not a realistic measure of whether or not the program is on target for meeting its goals, as illustrated in the chart above. The policy of the Rolling Portfolio would be better met if extended budgets and measurements of program performance were better aligned.

Furthermore, any evaluation of goals and cost-effectiveness should also take technical input updates into account. For example, using MCE's 2021 portfolio, MCE's avoided cost benefits from 2018-2020 would have resulted in a 19% reduction in cost-effectiveness over that two-year period, even if a portfolio of programs had achieved exactly what it proposed at the outset of the two-year period. This example also helps to illustrate why a 10% margin of difference may be too narrow. For these reasons, unless there is a 20% margin of difference or greater, PAs should be permitted programmatic discretion. Below the 20% margin of difference, PAs can still flag, at their own discretion, any meaningful variations from expected savings and cost-effectiveness targets that they believe merit special attention or interim action. However, there should be no mandatory reporting or remediation at that level.

7. **What is the expected outcome of having program administrators submit a Tier 2 advice letter if they are not "on-target" to meet their savings goals, or cost-effectiveness thresholds? Is Energy Division staff expected to review the program administrator's proposed mitigation measures and approve changes? If so, what are the standards of review, or criteria? If not, is there an alternative cycle length and budget authorization structure that would address these challenges? Please support your recommendation.**

MCE and BayREN suggest that the intended outcome of the trigger-based Tier 2 advice letter is for the PA to inform the Energy Division of any corrective actions that will be taken to achieve targets or to re-evaluate original targets, and for those actions to receive approval as appropriate. MCE and BayREN envision the Commission applying the same standards of review and criteria as for other Tier 2 advice letters.

<u>Transparency and opportunity for early stakeholder and ED input</u>

8. **How should staff or the Commission remedy a situation where the program administrator does not provide adequate corrective actions in the Tier 2 advice letter**?

MCE and BayREN have no comments with regard to Question 8 at this time but may address this question in reply comments.

9. **Should progress towards cycle goals and cost-effectiveness be assessed quarterly, yearly, annually, or in some other increment? Please address why the recommended increment is the most appropriate point, given the need to balance natural portfolio fluctuations and the time requirements of remediation efforts.**

The CAECC Proposal provides that PAs should be monitoring progress toward goals and cost-effectiveness on a quarterly basis. MCE and BayREN, however, assert that using such a short timeframe makes it very difficult to observe progress for several reasons, including:

- Project timelines are almost always longer than a quarter, which means that a PA will be recording project expenses before they begin to record any project savings;
- Projects tend to show substantial progress toward goals toward the end of the year or program cycle (as indicated in the chart above); and
- Technical input updates can have outsized impacts that substantially skew short-term assessments.

As described in response to Question 6 above, in-cycle fluctuations due to near-term program investments and technical input updates can substantially affect short-term assessments of long-term goals. For this reason, quarterly monitoring combined with Annual Reports may be appropriate but must be evaluated in the overall context of approved four-year program goals. Major changes will typically not be needed based on quarter-to-quarter fluctuations that do not necessarily reflect meaningful or unexpected variations with regard to multi-quarter or multi-year programs.

10. Should this process be based on a periodical "bus stop" basis or on a more "as needed" basis? Please explain your answer.

Opportunities for early input should be on an as-needed basis. PAs already report on progress on a quarterly basis and these reports are publicly available via CEDARS. No changes to the current process are suggested in the CAEECC Proposal. The PAs also solicit stakeholder feedback on progress in connection with the Annual Report and in presentations to the CAEECC. More frequent assessments tend to be inefficient and inaccurate because, as indicated earlier, short-term program snapshots tend not to clearly reflect progress toward long-term goals.

11. What is the oversight role for Energy Division in enforcing a trigger event, and how should the remediation Tier 2 advice letter be triggered: via Annual Report/ submission to the California Energy Data and Reporting System (CEDARs), via updates to technical inputs, either/both, or other? Please provide details to support your recommendation.

Although the CAEECC Proposal appears to suggest that a trigger-based filing could be required at *any time* within the cycle, MCE and BayREN recommend that the Commission require such reporting and remediation as needed *in year three* of a four-year program cycle, triggered by the Annual Report covering year two. Requiring a trigger-based Tier 2 Advice Letter in year three (if triggers are met) would provide an opportunity for intervention and modification in cases of substantial divergence from program goals. In contrast, requiring an interim filing if triggers are met *at any point* could lead to substantially distorted pictures of progress toward program goals. For example, if a PA has to invest a substantial outlay in program development in the first six months of a program, that could trigger a filing based on failure to meet cost-effectiveness goals, but progress toward cost-effectiveness goals cannot effectively be evaluated on such a short timeframe. For this reason, the PAs should only be required to assess whether they meet established "triggers" for remedial filing at reasonable junctures, such as two years into a four-year EE program cycle.

__**Flexibility/authority to adjust to changes in market and technology**__

12. The investor owned utilities (IOUs) are required to reach specific percentage targets for the proportion of their portfolios to be administered by third parties (ultimately, at least 60 percent). Because the IOUs cannot change program implementation plans for a third-party contract, the lever for a program administrator to ensure their portfolio is on target is to add/decrease effort in high-/poor-performing activities, respectively. Considering this, how can an appropriate level of oversight for program cancellation occur without impeding IOUs' ability to stay on target?

MCE and BayREN have no comments with regard to Question 12 at this time.

13. The Rolling Portfolio leveraged annual budget advice letters for oversight of program closures at a high level (e.g., is the closure justified given the constraint on the program administrator to meet required portfolio cost-effectiveness and savings goals; and did the program administrator develop and communicate a transition plan appropriate to avoid cliffs or gaps in the market). The NRDC motion proposes a program administrator would be required to submit a Tier 2 advice letter for every program closure.

a. What would staff's standard of review for program closure advice letters be?

b. Does this approach leave flexibility that the program administrator would need to meet its overall portfolio cost-effectiveness target and savings goals?

The Commission should not require that all program closures be filed via Tier 2 advice letters. While appropriate under some circumstances, some program closures reflect minor changes that do not rise to the level where a full Tier 2 advice letter is required. The EE programs are subject to specific constraints as to cost-effectiveness and savings goals, and sometimes programs must be closed to further those goals. Waiting a prolonged time period for approval to close a program that is not advancing specified cost-effectiveness and savings goals would exacerbate program inefficiencies. In order to ensure that there are no significant gaps in the market, without adding unnecessary delays or burdens, program closures should only require a trigger-based advice letter process when the closure accounts for a meaningful percentage of the PA's total energy efficiency portfolio.

MCE and BayREN propose that the Commission should require the trigger-based advice letter process only when the program closure exceeds 20% of the PA's total portfolio (in terms of the portfolio's forecasted budget). Requiring a Tier 2 advice letter for small program closures that will not cause substantial gaps in the market would be inefficient and would not further the Commission's goals. The PAs should retain the flexibility to close smaller programs without a full advice letter process. In the absence of the ABAL requirement, PAs would report on closures affecting smaller programs with detailed explanations in their Annual Report.

Guidance Decision

14. **The July 3, 2020 amended scoping ruling proposes the Commission issue a guidance decision addressing the NRDC motion in February or March of 2021. If the Commission issues a guidance decision in early 2021, what specific areas, inputs, portfolio direction should the Commission prioritize including in the guidance decision?**

MCE and BayREN do not currently have comments regarding the specific areas, inputs, and portfolio direction that the Commission should prioritize including in the guidance decision. However, a number of comments are provided below regarding the timelines and filing requirements proposed in the July 3 Scoping Ruling that are expected to be implemented in the anticipated Commission guidance decision.

The Commission should not require a universal re-filing of business plans in September 2021 by all PAs for several reasons. First, some business plans were only recently approved, are not ripe for re-filing, and progress toward goals could be harmed by imposing a re-filing requirement. Second, re-filing after such a short implementation window would be administratively burdensome, particularly for smaller PAs with program plans that have not been substantially affected by COVID. Third, as stated earlier, the re-filing of all business plans is not necessary absent the adoption of major policy changes because current business plans are geared to achieving currently effective policies. If the Commission does adopt major policy changes that require re-focused business plans, there must be adequate time for those policy changes to be incorporated into the revised plans, a process that requires significant time and effort.

MCE and BayREN's business plans are still relatively new and should not be interrupted at this early stage. MCE, for example, is just two years into a transition from a portfolio designed to fill gaps and to serve hard-to-reach customers, to a broader portfolio of programs. This portfolio of programs has more ambitious savings goals, is designed to be more cost-effective, is funded at a substantially higher level than MCE's prior programs, and serves a broader range of customers. Since the MCE Business Plan was approved in mid-2018, MCE has launched multiple new programs to serve industrial, agricultural and large commercial customers, as well as a residential behavioral program, a residential direct install program, and a workforce, education, and training program. In most cases, MCE is just starting to see the savings from these new efforts reflected in claimed savings. If MCE were required to re-file a new business plan in September 2021, it would be nearly impossible to evaluate the progress of many of MCE's programs at this stage of their implementation.

A requirement to re-file business plans would also impose an outsized burden on smaller PAs. Business plan applications consume a substantial amount of staff time and financial resources. MCE's Business Plan Application cost approximately $200,000 to prepare, which is the equivalent cost of approximately 54 small commercial projects or 6 multi-family property upgrades. If MCE and BayREN were required to re-file their business plans in September 2021, the cost and administrative burden could disproportionately disadvantage their operations relative to larger PAs with higher overall budgets and more staff resources.

The COVID-19 crisis also does not support a universal re-filing requirement because some programs are more affected than others. MCE and BayREN note that to date, they have not observed substantial impacts to their EE programs as a result of COVID-19. While re-filing may be appropriate for PAs that have observed major impacts due to the pandemic, these impacts are not ubiquitous and depend on program type and scope. Furthermore, there is still a lot of uncertainty about what the long-term impacts and recovery from the COVID-19 pandemic will look like. If necessary, it would be better to update program strategies once the pandemic has significantly slowed or ended, so that there is more certainty about the full impact of the pandemic on the economy as a whole, and the EE industry in particular.

Lastly, as indicated earlier, re-filing business plans is not merited absent major policy changes impacting the EE programs. The Commission is in the process of potentially adopting substantial policy changes that would affect EE savings and cost effectiveness goals in the guidance planned for issuance in the first quarter of 2021. If the Commission is unable to complete a thorough assessment of the policy issues at stake within that short timeframe, it should extend that process rather than requiring PAs to re-file their business plans. Re-filing business plans in the absence of major policy changes could lead to the need to refile multiple times to reflect updated policies.

Further, to the extent that the Commission does adopt major policy changes in the first quarter of 2021, MCE and BayREN are concerned that there will not be sufficient time between that decision and the re-filing of business plans in September 2021 to permit the PAs to develop alternate programs that meet the new policy goals. The CAEECC Proposal seeks nine months after the guidance decision is issued for portfolio planning and stakeholder review before a new business plan application is filed.[20] To the extent it becomes necessary to re-file EE business plans, MCE and BayREN generally agree with the CAEECC Proposal's concept of a less compressed timeframe for the following reasons.

Based on the experience of MCE and BayREN, preparing an ABAL, a process much simpler than the filing of a business plan application, typically takes approximately four months. By contrast, a business plan requires significant additional detail and, based on the initial business plans, took all PAs longer than 12 months to prepare. In addition, to the extent that the Commission adopts major policy changes, MCE and BayREN anticipate that other processes will be required, including updates to resources, tools, and measures such as the Cost-Effectiveness Test and CEDARS. Even if such updates are adopted in a rapid and timely manner, the PAs will require time to understand and utilize these updated tools in program planning and development. PAs will also need time to incorporate any new policy directives from the Commission into the business plans.

For these reasons, the Commission should: (1) act in the near-term to address structural and procedural changes such as changes to the ABAL process, including considering the option of switching to a biennial ABAL as discussed in Question 4 above, (2) allow current business plans of PAs that have met forecasted cost-effectiveness requirements to date to remain in effect, and (3) allocate additional time to consider and address more substantive policy issues, which

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[20] *See* CAEECC Proposal at 6, Section 4.2.

can be adopted over a longer timeframe and do not need to be fully resolved on the expedited timeline set out in the scoping memo.

15. **The NRDC motion identifies information to be included in the program administrators' applications. Given the information provided in the applications, what should be the Commission's standard of review, or criteria, to determine reasonableness of the applications? Should the Commission provide a detailed review of each program proposed, or focus on portfolio-level metrics, or evaluate sector-level strategies? Or should this review focus on other information provided?**

MCE and BayREN do not have comments at this time regarding how the Commission should implement the reasonableness standard. However, MCE and BayREN recommend that the Commission's review emphasizes high-level portfolio metrics. In addition, MCE and BayREN would like to take the opportunity to provide input related to the Commission's review of portfolio- and sector-level metrics more generally, including the Commission's requirement that the PAs track an extensive range of individual metrics. In particular, the Commission should revisit the number and breadth of metrics that PAs are asked to track.

Under Decision 18-05-041, PAs are currently required to track over 300 different individual metrics toward EE goals at the portfolio and sector levels.[21] In revising the program tracking and review process, the Commission should work to ensure that all metrics are appropriate, measurable, and incorporate stakeholder input. Individual tracking of a proliferation of metrics is time-consuming, burdensome, and may not accurately reflect priorities. Moreover, some of the current metrics are not measurable with currently available data.

MCE and BayREN also note that reports and outputs made publicly available via CEDARS can be readily used to evaluate programs and to gather a range of metrics concerning

[21] *See* D.18-05-041, Attachment A in A.17-01-013, issued June 5, 2018.

program performance and implementation. Currently, certain metrics that the PAs are asked to track duplicate information that is already readily available via CEDARS. MCE and BayREN suggest that the PAs not be required to report on the metrics that may be gathered from publicly available databases. Increasing efficiencies in this way will reduce duplicative administrative burdens and enable improved use of funds and resources. Finally, stakeholder input should be solicited and considered in updating the requirements for tracking individual metrics.

16. What additional information should be included in the applications to facilitate the Commission's reasonableness review? For instance, should the applications include portfolio and sector metrics, and implementation plans for every new or revised program proposed?

In the event that the Commission reviews the existing metrics as proposed in response to Question 15, MCE and BayREN would support applications that encompass both portfolio- and sector-level metrics; more granular metrics should be reserved for an implementation plan.[22]

An implementation plan should not be required as part of the application nor should implementation plans be formally reviewed by the Commission. The implementation plan process should be maintained as outlined in D.15-10-028, which requires that the implementation plan be posted online but not filed formally with the Commission.[23]

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[22] *See* D. 15-10-028 at 53, 54, 64, and Appendix 4: Implementation Plan Template at 3 in R.13011-005, issued Oct. 28, 2015.
[23] *See id*. at 43.

Cost-Effectiveness

17. For the purpose of approving budgets and assessing cost-effectiveness, what should be the distinction (if any) between program administrator and program implementer costs?

a. What is the rationale behind the Commission reviewing program administrator and program implementor costs separately, when historically program administrators have been ultimately responsible for developing contracts with program implementors and reporting cumulative program costs?

Program administrator and program implementer costs should continue to be reported cumulatively and should not be reviewed separately.

b. If reviewed separately, should both program administrator and program implementer costs be capped at 10 percent cumulatively?

In any event, the Commission should maintain the 10% cap for utility program administrative costs as well the 10% target for third-party administrative costs, and other soft targets for the remaining cost categories as established in the EE policy manual.

18. How would assessing cost-effectiveness over multiple years impact the Commission's current cost-effectiveness calculations? In your response, please consider elements like assigning an avoided cost vintage to each year, the yearly attribution of costs to savings, and whether the achievement of cost-effectiveness targets would be assessed using a weighted average or cumulative calculation.

MCE and BayREN have no comments with regard to Question 18 at this time but may address this question in reply comments.

Technical Inputs

19. The proposal references misalignment resulting from changing policies and technical values following goals adoption and challenges for program administrators preparing budget filings when critical input values are actively changing. Please provide specific, quantitative evidence of instances where misalignment or difficulties occurred due to changing technical inputs.

MCE and BayREN have observed misalignment such as that referenced in the CAEECC Proposal. The most glaring example of this concerns the Potential and Goals study. The

Potential and Goals study is a bottom-up forecast based on technologies and market status in each IOU territory at a certain point in time.[24] MCE and BayREN observed misalignment issues with regard to the Potential and Goals adoption for program years 2020 and 2021. The Database of Energy Efficiency Resources ("DEER") was relied on in carrying out the Potential and Goals study, but the DEER update for program year 2021 required significant updates to technical inputs including revisions to DEER 2020.[25] DEER technical values are updated annually to reflect new market conditions and to inform the direction of EE programs. However, these updates can result in misalignments between the DEER values that are used to determine the technical potential in the relevant Potential and Goals study and the DEER values that are used during the implementation years for that same period. That was the case with respect to the recent Potential and Goals studies.

Another example of such misalignments has occurred in the context of avoided cost inputs. The 2019 Energy Efficiency Potential and Goals study published on July 1, 2019 did not use the most recent avoided costs available at the time, which had been adopted by the Commission on May 16, 2019. However, PAs were still required to use the avoided costs adopted on May 16, 2019 in their 2020 ABALs. This resulted in a misalignment as to avoided cost inputs between the ABALs and the Potential and Goals study.

The Potential and Goals study also does not provide information regarding non-resource programs. The failure to consider non-resource program costs and their impact on the overall cost-effectiveness of program portfolios can result in an inaccurate and incomplete picture of

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[24] There is misalignment in that the Potential and Goals study is based on IOU territories, yet MCE and BayREN serve just a small part of one IOU territory.

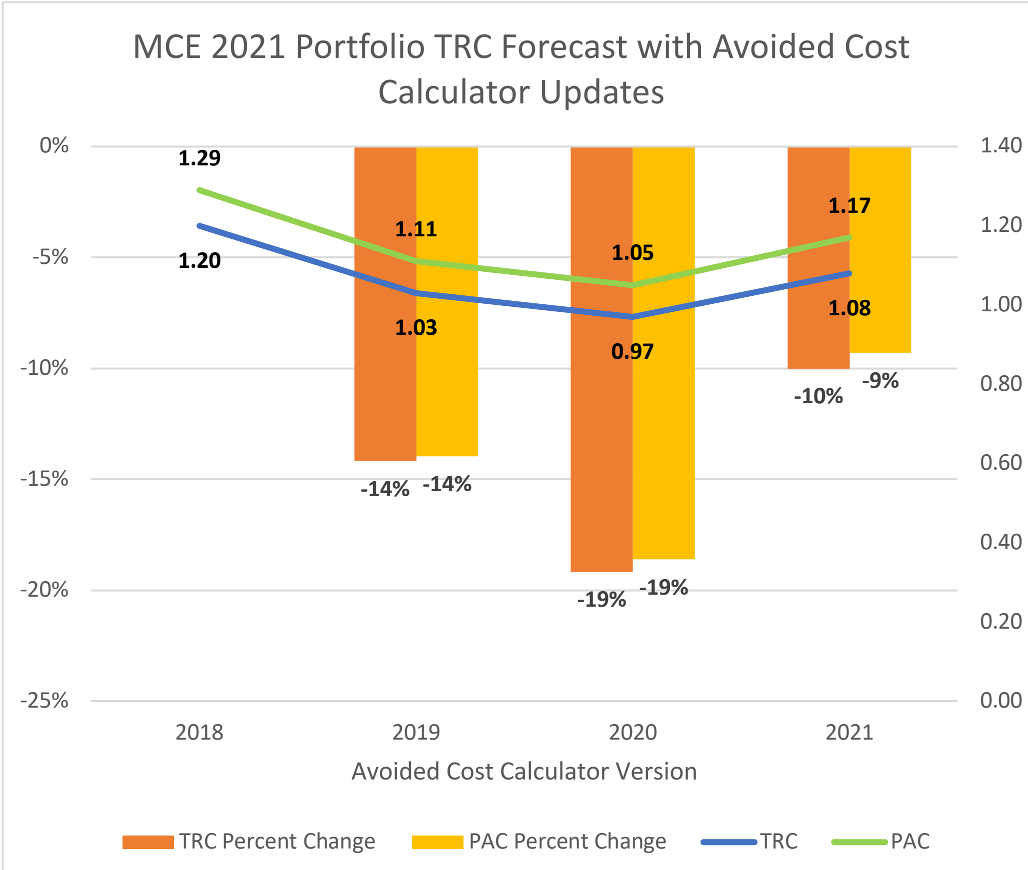
[25] *See* Resolution E-5009, issued Sept. 16, 2019 (Approval of the Database for Energy-Efficiency Resources updates for Program Year 2021 and revised version for Program Year 2020). *See also* http://DEERresources.com.

portfolio cost-effectiveness as well as the achievement of Commission and state policy objectives.

MCE and BayREN have also observed challenges for PAs preparing budget filings when critical input values are actively changing. For instance, the Avoided Cost Calculator ("ACC") was adopted on June 25, 2020 and subsequently incorporated into CEDARS production on July 16, 2020. As a result of this timing, the PAs had just three weeks remaining to develop draft ABALs for presentation to the CAEECC, which were due on July 28, 2020. This did not allow sufficient time for the PAs to perform proper portfolio planning to ensure a cost-effective filing. Due to the fact that it takes many months to plan and develop a major filing, PAs must rely on the most current version of the ACC. After an updated version of the ACC is released, PAs must then re-evaluate their program portfolios using the new ACC and redo their analysis. This process is very challenging and presents risks for PAs, as it is difficult to predict the magnitude or direction of updates to the ACC.

In order to demonstrate how substantial the year-to-year changes to the avoided cost update can be, MCE ran its 2021 portfolio through ACC versions for the past three years with no changes to the data inputs. MCE's Total Resource Cost test results for its 2021 portfolio were 0.94 and 1.05 when the 2020 and 2021 versions of the ACC were used, respectively. No other changes were made to the data inputs. However, when using the 2020 ACC the programs were not considered cost-effective, but when using the 2021 ACC they were cost-effective.

Although this year the avoided cost update was favorable to MCE's programs, in past years the avoided cost updates had been trending downward in terms of evaluating cost-effectiveness. This trend is depicted in the graph below, with the most recent year rising but prior years showing descending values.



20. **Is it reasonable to forgo utilization of annually updated avoided cost values to address energy efficiency portfolio process concerns described in the proposal? Why or why not?**
    a. **Do the benefits of utilizing a single avoided cost vintage for two years outweigh the drawbacks of energy efficiency being out of step with other CPUC energy programs that utilize the Avoided Cost Calculator, such as building decarbonization (R.19-01-011), net energy metering (R.14-07-002), energy storage (R.15-04-011) and demand response (R.13-09-011)? What would be the impact of misalignment between energy efficiency and the integrated resource planning proceeding (R.16-02-007)?**

    b. **Decision (D.) 19-05-019 states that minor changes include data and input updates in addition to changes to the modeling method that parties can reasonably agree are minor in scope or impact. Though described as minor changes, data updates can meaningfully impact avoided costs. Given this information, what metrics do parties use to define avoided cost updates as either material or immaterial?**

MCE and BayREN believe it is reasonable to forgo annual updated avoided cost values for purposes of EE programming**.** MCE and BayREN support the CAEECC Proposal to conduct major ACC updates on a two-year cycle instead. All ACC updates can be effectively incorporated into that two-year cycle, thereby streamlining the process, creating fewer discrepancies, and maintaining sufficient accuracy.

21. The proposal recommends that updates to technical inputs, engineering (Database for Energy Efficiency Resources (DEER)) values and evaluation, measurement and verification (EM&V) be changed to every two years as opposed to annually.

a. How often should technical inputs and DEER values be assessed to avoid utilizing stale, inaccurate, or out-of-date values?

MCE and BayREN agree with the CAEECC Proposal that technical inputs and DEER values should be assessed on a two-year cycle. This will enhance stability and allow for increased alignment while maintaining sufficient accuracy.

b. DEER values were to be updated every other year, when should updates become effective?

All updates to ex-ante technical inputs such as DEER savings, net-to-gross ratios, and installation rates should be provided to PAs in a timely manner that allows the PAs to process and determine impacts to current program portfolios and report on such impacts, as well as strategies to respond to those impacts, in mid-cycle reports. These values should be set early enough to support the application planning process.

c. Should DEER values be frozen for some or all of the portfolio cycle? Why or why not?

MCE and BayREN recommend that DEER values be frozen for the two-year period. Making changes on a more frequent basis creates costly planning adjustments and makes it challenging to assess the success of a program. As described earlier, more frequent updates result in programs being measured by different parameters than the parameters under which they were designed.

d. Would moving EM&V results from annual to every other year have adverse effects to portfolio assessment and other processes such as DEER updates or energy savings performance incentive (ESPI) if maintained in its current form?

Moving EM&V results from annual to every other year might allow the results of EM&V to be incorporated more fully, particularly if the results are aligned with mid-cycle and four-year advice letters. We do not anticipate adverse impacts, and any increased alignment would be beneficial.

22. D.15-10-028 adopted a "bus stop" schedule for various activities of the Rolling Portfolio. Thinking of when in the year these bus stops occur, do you think the existing schedule should change to accommodate the process changes proposed in the NRDC motion?

a. Please outline any necessary changes to accommodate any alternative proposals you made in your answers above.

All activities within the existing "annual bus stop" should be updated to align with the biennial cycle described in the CAEECC Proposal for the four-year cycle. All values should also be frozen for that two-year period in order to align goals with DEER and ACC updates, as well as portfolio implementation. Any technical update that impacts the filing should be scheduled at least four months prior to the filing in order to allow a reasonable amount of time for the PAs to incorporate those updates into the program portfolios. If not, substantial misalignments such as those described in response to Question 19 may persist.

IV. CONCLUSION

MCE and BayREN thank Commissioner Randolph, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of these comments.

Respectfully submitted,

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September 1, 2020

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

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON SECTIONS 6, 11.1 AND 11.2 OF THE ENERGY DIVISION STAFF PROPOSAL FOR A TRANSPORTATION ELECTRIFICATION FRAMEWORK

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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

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON SECTIONS 6, 11.1 AND 11.2 OF THE ENERGY DIVISION STAFF PROPOSAL FOR A TRANSPORTATION ELECTRIFICATION FRAMEWORK

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC") and the *Email Ruling Resetting Procedural Schedule for Comments on Transportation Electrification Framework Sections,* dated August 4, 2020, the Joint Community Choice Aggregators ("Joint CCAs") submit these reply comments on Sections 6, 11.1 and 11.2 of the Draft Transportation Electrification Framework ("TEF").[1] The Joint CCAs submit these reply comments for the limited purpose of responding to the comments of the Green Power Institute and Community Environmental Council ("GPI/CEC").

I. REPLY COMMENTS

A. The Joint CCAs Agree That CCAs Should Be Permitted to Access Funding

In opening comments, GPI/CEC suggest that "[t]hird parties such as [Community Choice Aggregators ("CCAs") and Community-Based Organizations [("CBOs")] may be best situated to

[1] The Joint CCAs consist of Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCP"), California Choice Energy Authority ("CalChoice"), Silicon Valley Clean Energy Authority ("SVCE"), East Bay Community Energy ("EBCE"), Redwood Coast Energy Authority ("RCEA"), the City of San José, Peninsula Clean Energy ("PCE") and Clean Power Alliance of Southern California ("CPA"). Note that the group of CCAs that comprises the Joint CCAs, as defined in this filing, is not identical to the group of CCAs that filed under this designation in opening comments.

deliver effective [Marketing, Education and Outreach ("ME&O")]."[2] More specifically, GPI/CEC "recommend that the *majority* of ME&O *funding* for [Transportation Electrification ("TE")] go to third-party organizations such as CCAs and CBOs for more focused Deep ME&O..."[3] GPI/CEC argue that since CCAs and CBOs know their local territories very well, have lower cost structures, and are nimble, they are "highly appropriate for testing TE ME&O strategies in many diverse settings, iterating quickly, and enabling innovative and successful strategies to emerge and spread across California."[4] The Joint CCAs agree with GPI/CEC that CCAs have an important role to play in TE efforts, and more importantly, agree that the inherent strengths of CCAs ought to be utilized in order to advance and accelerate TE across California. Given their connections to the local communities they serve, and their role as the default load serving entity ("LSE") in these communities, CCAs have unique advantages and are well positioned to implement and design TE programs, including ME&O programs.

B. The Joint CCAs Agree That CCAs Should Be Permitted to Serve as TE Program Administrators

In response to the stakeholder question regarding the appropriate role of CCAs in advancing Vehicle Grid Integration ("VGI"), GPI/CEC suggest that "CCAs should be able to assume administration of TE programs for their territory, to exactly the same degree as [investor-owned utilities ("IOUs")] would otherwise. . ."[5] The Joint CCAs agree. As will be discussed

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[2] GPI/CEC Opening Comments at 14.

[3] GPI/CEC Opening Comments at 16 (emphasis added). *See also* GPI/CEC Opening Comments at 13 (GPI/CEC explain that "deep ME&O" is expanded and targeted outreach that could include many initiatives, including for example: (i) additional focused outreach and education at workplaces that have added chargers, (ii) distribution of marketing collateral on utility rebate and EV rate programs and benefits of EVs, (iii) "EV 101" presentations via webinar or in person "lunch and learns," (iv) EV showcases at the largest employers, and (v) other creative strategies like those being piloted by many CCAs.)

[4] GPI/CEC Opening Comments at 16.

[5] GPI/CEC Opening Comments at 5.

further in the Joint CCAs' comments on Section 10 of the Draft TEF, CCAs should be permitted to serve as Program Administrators of TE Programs. Therefore, CCAs should also be permitted to draft and file their own Transportation Electrification Plans ("TEPs"), as well as applications and advice letters for approval of their own ratepayer-funded TE programs and pilots.

As GPI/CEC noted in their opening comments, "CCAs are now a major force in California's energy landscape, and should be allowed access to TE *funds for infrastructure development and ME&O* to test the proposition that they can deliver increased charger deployment and utilization at lower cost than current IOU programs."[6] The Joint CCAs emphasize that granting CCAs access to *funding* in order to promote and accelerate TE is critical. As will be discussed in the forthcoming comments on Section 10 of the Draft TEF, many CCAs are already offering unique and successful TE programs. However, these programs are currently funded largely, if not entirely, utilizing CCA *generation* revenue, which results in CCAs being limited in their ability to scale up their current program offerings. Therefore, in order for the inherent strengths of CCAs to be harnessed and to address competitive inequities, the Commission should permit CCAs to serve as Program Administrators that are able to access ratepayer funds for TE programs and pilots.

C. The Joint CCAs Support GPI/CEC's Proposal for CCAs to Be Able to Access Funding for TE Pilots

In opening comments, GPI/CEC specifically propose two pilots with associated funding. The first pilot proposal would allow IOUs and/or CCAs with CBO partners to apply for up to $4 million in priority pilot "no regrets" funding to test "Deep ME&O" at sites that have chargers already deployed through IOU charger programs.[7] GPI/CEC also propose a second pilot with an

6 GPI/CEC Opening Comments at 16 (emphasis added)
7 *See* GPI/CEC Opening Comments at 18.

additional $4 million that would allow IOUs and/or CCAs to work with CBOs to pro-actively identify potential sites for installing dual-use (*e.g.,* workplace and multi-unit dwelling ("MUD") access) electric vehicle ("EV") chargers.[8]

The Joint CCAs agree that CCAs should be permitted to apply for funding for these types of pilot programs. More importantly, the Joint CCAs support the GPI/CEC proposals for testing the potential of "Deep ME&O" to increase TE at low cost.[9] The Joint CCAs agree with GPI/CEC that focused ME&O activities, such as EV awareness days, EV Ride and Drives, EV vehicle displays, EV 101 webinars and/or lunch and learns or presentations at workplaces, as well as other creative ME&O strategies, should be expeditiously considered by the Commission under the TEF as "no regrets" priority projects. The Joint CCAs see value in developing these pilots in consultation with CCAs and CBOs in order to test deep ME&O and dual-use charging scenarios, and offer a few additional recommendations regarding these proposals below.

D. Additional Recommendations Related to the GPI/CEC Proposals

While the Joint CCAs support the majority of statements and proposals made by GPI and CEC in opening comments, the Joint CCAs propose a few additional thoughts to round out the proposals. The Joint CCAs appreciate that GPI/CEC suggest EV "Ride and Drives" as a potential ME&O event.[10] The Joint CCAs support these types of events since individual's direct experience with EVs has been shown to be an extremely effective factor in driving EV adoption. In addition to "Ride and Drives," the Joint CCAs suggest that one-on-one dealer experiences, as well as EV rentals, are other ways that potential EV purchasers can experience EVs directly. The Joint CCAs suggest that CCAs and/or CBOs partnering with local car rental companies and

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8 *See* GPI/CEC Opening Comments at 19.
9 *See* GPI/CEC Opening Comments at 18.
10 *See* GPI/CEC Opening Comments at 19.

dealerships could facilitate these types of interactions for potential buyers within a community. The Joint CCAs suggest that these types of experiences should be considered as additional ME&O strategies.

With respect to the GPI/CEC proposal for dual-use case charging scenarios (such as workplace/MUD or workplace/fleet), the Joint CCAs believe that dual-use installations are a concept worthy of consideration, particularly for public sector installations. However, there are barriers to these types of installations that need to be considered, including the California Air Resources Board regulations on payment systems, liability and insurance, and security concerns. Private sector installations are also likely to have access barriers. For these types of installations, the Joint CCAs believe a pilot project is reasonable, but if such a pilot is pursued, the Joint CCAs recommend focusing on the public sector rather than the private sector. In addition, the pilot should specifically assess barriers, and provide guidance on resolving the barriers. The pilot should also explore use of lower cost Level 1 charging for long-dwell scenarios. In general, the Joint CCAs believe that ease and availability of Level 1 charging should be considered more broadly, since the majority of EV drivers today use Level 1 charging. For example, Level 1 charging is a cost effective way to quickly deploy EV charging in MUDs.

Finally, the Joint CCAs diverge from GPI/CEC in deemphasizing the linkage between ME&O and "driving utilization." While GPI/CEC correctly identify the high per port costs associated with IOU projects, there are many reasons why utilization can be low in certain segments.[11] For example, in municipal fleet scenarios, utilization can be expected to be low, since municipal fleet vehicles typically have much lower vehicle miles traveled than personal vehicles (6,000 miles/year or less, compared to personal vehicles at 12,000 miles/year or more).

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11 *See, e.g.*, GPI/CEC Opening Comments at 11.

In addition, deployments in MUDs, especially apartments, can be expected to have low initial utilization due to a lag time between installations and tenants getting or arriving with EVs. This lag time may be several years. Therefore, while utilization is important, it should not be the primary focus for ME&O efforts.

II. CONCLUSION

The Joint CCAs thank Assigned Commissioner Rechtschaffen and Administrative Law Judges Doherty and Goldberg for their consideration of the matters discussed herein. The Joint CCAs look forward to continuing to participate in this proceeding in order to ensure that CCA programs are enabled to serve as effective partners in the TE space moving forward.

Dated: September 4, 2020

Respectfully submitted,

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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)

**RESPONSE OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION
TO PACIFIC GAS AND ELECTRIC COMPANY,
SOUTHERN CALIFORNIA EDISON COMPANY, AND
SAN DIEGO GAS AND ELECTRIC COMPANY'S
PETITION FOR MODIFICATION**

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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)

RESPONSE OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS AND ELECTRIC COMPANY'S PETITION FOR MODIFICATION

Pursuant to Rule 16.4 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Community Choice Association ("CalCCA") hereby submits this response to the Petition for Modification ("PFM") of Decision ("D.") 18-10-019 by Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas and Electric Company (collectively, the "Joint Utilities").

CalCCA does not oppose the PFM's request to modify the treatment of line losses in calculating Power Charge Indifference Adjustment ("PCIA") rates. Today, the investor-owned utilities ("IOUs") apply line loss factors to first determine a utility's total portfolio cost at the customer meter, and then they reverse that application of line losses to determine total portfolio value at the generation meter. The difference between total portfolio cost and market revenue comprises the "indifference amount" component of the PCIA revenue requirement for a given year.

The PFM proposes, instead, to use forecasted generation volumes to calculate both the total portfolio cost of energy and the total portfolio value of energy at the generation meter instead of at the customer meter. This approach would eliminate a mathematical error that currently exists when line losses are applied by removing line losses from the equation altogether when calculating the indifference amount. It would also avoid the application of a line loss factor to capacity, which the IOUs allege is inappropriate. The Joint Utilities' proposed methodology appears correct.

However, if the Commission should act on the PFM, CalCCA respectfully requests the Commission clarify that the shift away from forecasted retail sales volumes to generation volumes will not replace the use of load forecasts in other components of the PCIA methodology. IOU load forecasts are a key input through the methodology and should continue to be used, for example, (1) to determine the billing determinants used to allocate the PCIA revenue requirement; (2) in the cost production modeling that results in forecasted generation volumes; and (3) when validating that Retained RPS amounts meet or exceed the IOUs' annual RPS compliance targets.

I. CALCCA DOES NOT OPPOSE THE PFM PROVIDED MINOR CLARIFICATIONS ARE MADE.

The PFM addresses a common workpaper template adopted in D.17-08-026 that is included in each utility's calculation of the indifference amount in the ERRA forecast proceedings.[1] The indifference amount is the difference between the forecasted cost of a utility's generation portfolio and the forecasted market value of the generation portfolio for the target year. It is one of two key components when calculating the revenue requirement underlying the PCIA rates that departing customers pay, with the other component being the forecasted year-end

[1] R.17-06-026, *Petition for Modification of Decisions 17-08-026 and 18-10-019 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)*, p. 5 (Aug. 7, 2020) ("PFM").

balance in the Portfolio Allocation Balancing Account ("PABA") for the year in which the forecast proceeding takes place.

The PFM asserts the common template contains two errors. The first is the application of line losses when calculating the value of procured Resource Adequacy ("RA") capacity in the indifference amount, and the second is a math error that occurs when the line losses are used to scale down and scale back up energy volumes measured at the generation meter.[2] The Joint Utilities seek to resolve those errors by using forecasted generation volumes to set the indifference amount, thereby removing line loss factors from the indifference calculation and ensuring such factors are not applied to RA capacity.[3] The Joint Utilities argue the language and appendices in D.17-08-026 and D.18-10-019 should be revised to achieve this result.[4] CalCCA does not oppose this request.

With the adoption of generation energy volumes as the proper input for calculating portfolio costs and market value, the Commission should clarify that use of generation volumes should be limited to revising the calculation of the indifference amount within the specific common workpaper template that calculates the vintaged indifference amount, *i.e*. Appendix A to the PFM.[5] Modifications to D.17-08-026 and D.18-10-029 should not include replacing the use of utility forecasts of customer-metered volumes in other parts of the PCIA calculation. The PFM is unclear on this point, suggesting at one point that "generation volumes be used to calculate the PCIA."[6]

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2 *Id*. at 2-4, 12-13.

3 *Id*. at 12-13.

4 *Id*. at 13-15.

5 *See id*. at Appendix A.

6 *Id*. at 12.

While perhaps unintentional, that language suggests a broader revision to the PCIA calculation beyond the common template and indifference amount calculation. Calculating the PCIA involves much more than just the indifference amount. Once the indifference amount is calculated, it is added to the forecasted year-end PABA overcollection (or undercollection) to form the revenue requirement underlying PCIA rates. That revenue requirement is then allocated among both bundled and unbundled customers based on their vintage, *i.e.*, the year unbundled customers left a utility's service,[7] and their rate class using the allocation factors from the utility's most recently approved general rate case.[8]

Utility load forecasts should continue to be used to determine the billing determinants resulting from those allocation factors.[9] The Commission also should make clear that IOU load forecasts predicting customer usage at the customer meter for the forecast year will continue to be a key input in the cost production modeling that results in forecasted generation values.[10] Finally, load forecasts are an important factor in validating the Retained RPS amounts the utilities forecast will be needed to meet or exceed the IOUs' annual RPS compliance targets because they form the basis of those compliance targets.[11]

7 R.07-05-025, D.11-12-018, p. 9 (December 1, 2011).

8 D.18-10-019, p. 122 and Ordering Paragraph 4 (October 11, 2018).

9 *See, e.g.,* A.20-07-004, SCE Prepared Testimony, *Energy Resource Recovery Account (ERRA) 2021 Forecast of Operations*, at 10:8 to 13:6 (July 1, 2020) (describing the sales forecast used for rate setting and the methodology used to set that forecast).

10 *See, e.g., id.* at 25:15-18; A.18-06-001, PG&E Exh. 1 at 3-6:29-32 (June 3, 2018) (stating that all of the generation resources and loads in a utility's bundled electric portfolio are modeled within PG&E's economic dispatch modeling).

11 *See* D.20-02-047 at pp. 13-16 (describing how retail sales are multiplied by a utility's annual RPS compliance target to determine a minimum amount of Retained RPS that must be included in each year's forecast).

II. CONCLUSION

While not a comprehensive list of areas in which load forecasts are used within the ERRA forecast proceedings, these three examples illustrate the importance of limiting the PFM's effects to the common workpaper template and the calculation of the indifference amount. CalCCA appreciates the opportunity to provide this Response to the PFM and suggests that if the Commission act upon the PFM, it include such clarifications to appropriately limit the PFM's effect.

Dated: September 8, 2020

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Re: **Protest of the Joint CCAs to Pacific Gas and Electric Company Advice Letter 5918-E, Implementation Plan for Community Microgrid Enablement Program in Compliance with D.20-06-017**

Dear Tariff Unit and Mr. Randolph:

Pursuant to Section 7.4 of California Public Utility Commission ("Commission") General Order ("GO") 96-B, Marin Clean Energy ("MCE")[1], Peninsula Clean Energy Authority ("PCE")[2], East Bay Community Energy ("EBCE")[3], and Central Coast Community Energy ("3CE")[4],

[1] MCE, California's first CCA, is a not-for-profit public agency that began service in 2010. MCE is a community-based and customer-focused public agency serving 34 communities across Marin, Napa, Contra Costa, and Solano counties.
[2] PCE, a community-controlled public agency, is a joint powers authority formed in 2016 by San Mateo County and all 20 of its cities and towns with a mission to reduce greenhouse gas emissions and expand access to sustainable and affordable energy solutions.
[3] EBCE is a Joint Powers Authority formed in 2016 by the County of Alameda and 11 cities incorporated therein. On March 9, 2020, the Commission certified Addendum #1 to EBCE's Implementation Plan and Statement of Intent, adding the cities of Newark and Pleasanton, as well as the city of Tracy in San Joaquin County, to EBCE's service territory beginning in 2021. EBCE is currently one of the largest Community Choice Aggregators ("CCAs") in the state.
[4] 3CE is a Joint Powers Authority formed as Monterey Bay Community Power Authority. It began service in 2018 to Monterey, Santa Cruz and San Benito counties. In 2020 service to certain cities in San Luis

(together the "Joint CCAs"), submit this protest to Pacific Gas and Electric Company ("PG&E") Advice Letter ("AL") 5918-E, *Implementation Plan for Community Microgrid Enablement Program in Compliance with D.20-06-017,* ("CMEP Implementation Plan"), submitted on August 17, 2020.

I. BACKGROUND AND INTRODUCTION

The Commission initiated Rulemaking ("R") 19-09-009 ("Microgrid OIR") in September 2019 to develop a policy framework for the commercialization of microgrids and related resiliency strategies. On January 21, 2020, PG&E filed its *Track 1 Proposal Addressing Immediate Resiliency Strategies for Outages* in response to the assigned Commissioner's Scoping Memo and Ruling from December 20, 2019. In this proposal, PG&E introduced the idea of the Community Microgrid Enablement Program ("CMEP"), to provide technical and financial support for community-supported microgrids that address Public Safety Power Shutoff ("PSPS") events.

On June 11, 2020, the Commission adopted Decision ("D.") 20-06-017 which approved PG&E's CMEP from 2020-2022 with modifications.[5] The Decision also required PG&E to file an Implementation AL, within 60 days of issuance of the Decision, to describe the program's scope, project applicability, eligibility requirements and other program details.[6] PG&E submitted the CMEP Implementation Plan in an advice letter filing on August 17, 2020.[7] The protest by the Joint CCAs submitted herein addresses this AL filing.

Obispo county was started. Additional San Luis Obispo cities and Santa Barbara county jurisdictions will receive service starting in 2021. To better reflect its expanded service area in 2020 the name was changed to Central Coast Community Energy.

[5] D.20-06-017, *Decision Adopting Short-Term Actions to Accelerate Microgrid Deployment and Related Resiliency Solutions,* OP 16 at 130.

[6] Id, OP 17 at 131.

[7] PG&E Advice Letter 5918-E, *Implementation Plan for Community Microgrid Enablement Program in Compliance with D.20-06-017* (CMEP Implementation Plan)

II. PROTEST

The Joint CCAs applaud PG&E for proposing the creation of the CMEP and appreciate PG&E's outreach efforts to date to collect feedback on program implementation details from local government and other community stakeholders. While the Joint CCAs agree with the large majority of the program requirements described in the CMEP Implementation Plan, some of the proposals, while well intended, may lead to complex and ambiguous program requirements. The Joint CCAs submit this protest with three goals in mind:

(1) PG&E must establish clear and verifiable program guidelines from the start to enable successful program participation;

(2) Customers must receive assurances about receiving the cost offset during early stages of project development to reduce risks; and

(3) The Joint CCAs would like to highlight some policy-focused issues proposed in the AL that should be discussed further in Track 2 of the microgrid proceeding.

The Joint CCAs look forward to working with PG&E on the joint development of multi-customer microgrids and stand ready to collaborate with PG&E in the implementation of the modifications to the CMEP program rules as discussed below.

1. Establish Clear and Verifiable Program Guidelines to Enable Successful Program Participation

A. Community Microgrid Eligibility Rules Must Be Based on Clear and Verifiable Metrics and Must be Expanded to Include Customers Impacted by Outages Triggered by Natural Disasters

PG&E describes the eligibility criteria for community microgrids under the CMEP in section 6 of the CMEP Implementation Plan.[8] While the Joint CCAs agree with the majority of the proposed eligibility criteria, there are few clarifications and modifications that should be made to the proposals.

In regards to locational eligibility criteria, the CMEP Implementation AL states that "at least one customer served by the microgrid must be located either in a Tier 2 or Tier 3 High Fire Threat District (HFTD) at the time of CMET application, in an area that has been impacted by a PSPS event in the past, or is in an area prone to outages."[9] The Joint CCAs strongly recommend that customers who have been impacted by outages triggered by natural disasters, such as wildfires, thunderstorms, flooding etc., should also be eligible for participation in the CMEP.

Additionally, the Joint CCAs are concerned about the vague nature of the requirement to not consider projects eligible that are located in areas that are excluded from all "reasonably anticipated potential future PSPS events due to other PSPS mitigation activities".[10] While the Joint CCAs understand the intent behind this requirement, this eligibility requirement is impractical, too vague, and challenging to implement. The Joint CCAs are not aware of any publicly available information that could be utilized to assess areas of PG&E's service territories that are likely excluded from PSPS events which means communities seeking assistance in developing microgrids would be denied program support only after the submit an application. This outcome is inefficient and would likely lead to dissatisfaction from communities that are denied participation after having spent time developing an application. Moreover, PSPS events are not

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[8] AL 5918-E at 11 and 12
[9] Id. at 12
[10] Id. At 12, footnote 18

the only events that can impact the ability of the distribution system to remain energized. Limiting program eligibility to only areas that could experience a PSPS event leaves communities seeking microgrids to increase resiliency and maintain societal continuity in the face of other grid events out of the program. The Joint CCAs recommend that PG&E elaborate on the need for this requirement or alternatively delete it.

Finally, the Joint CCAs would like to highlight one minor clarification regarding the definition of "Critical Facilities" as proposed in Appendix 5 of the CMEP Implementation Plan. As currently proposed, the CMEP relies on the definition of critical facilities put forth in D.19-05-0421 under the PSPS Proceeding.[11] The Joint CCAs would like to note that there was an updated list of critical facilities and critical infrastructure developed in a subsequent Decision under the PSPS Proceeding, Decision 20-05-051. The CMEP definition of "critical facilities" should be updated to reflect D.20-05-051 (and any future iteration of the definition developed under the PSPS proceeding).

B. The Application Process and Access to Separate Funding Buckets for Prioritized Projects Must Be Clarified

As a general matter, the Joint CCAs strongly support prioritizing CMEP resources for projects that serve disadvantaged and vulnerable communities, as well as those that are most urgent for public health, safety and public interest. However, the proposed requirements regarding prioritization criteria and process, as well as access to separate funding buckets for prioritized projects, require clarification.

[11] CMEP Implementation Plan, Appendix 5

First and foremost, it is unclear if projects that are most urgent for public health, safety and public interest, as described in section VII.B of the CMEP Implementation Plan, also get access to the separate funding bucket as described for projects in disadvantaged communities ("DACs") and vulnerable communities. The Joint CCAs request PG&E clarify this point. If PG&E does not intend to give those projects access to the separate funding buckets, the Joint CCAs ask PG&E to clarify what type of service or advantage those projects will receive beyond what is offered to non-prioritized CMEP projects.

Secondly, the Joint CCAs also caution that it is very challenging, if not impossible, to determine specific and verifiable metrics to determine "urgency for public health, safety and public interest". The CMEP Implementation Plan acknowledges as much by stating that assessing the risks facing a community is "not an exact science".[12] This leaves project prioritization to the utilities' discretion which raises equity concerns and leaves the program vulnerable to dispute and litigation. The Joint CCAs strongly recommend that PG&E develop clear and verifiable metrics to determine which projects are most urgent for public health, safety and public interest.

Third, based on the current CMEP Implementation Plan, it is not obvious to the Joint CCAs how PG&E intends to reconcile project prioritization with the statement that communities would be admitted to the program on a first-come, first-served basis.[13] It is unclear to the Joint CCAs how PG&E intends to handle, as a practical matter, project prioritization for projects that are most urgent for public health, safety and public interest. For example, if a project meeting these criteria is proposed to PG&E while non-priority projects are already being assessed for the cost offset,

[12] AL 5918-E at 14
[13] Id. at 10

would the prioritized project "jump the queue" ahead of the non-prioritized projects? If those prioritized projects would then access the same bucket of funding as non-prioritized project, and potentially deplete available funding, this could lead to widespread frustration, as well as wasted time and resources, for non-prioritized customers that are already well into the project development process.

Finally, PG&E should clearly outline in section VII of the CMEP Implementation Plan how project applications will be processed for prioritized projects. In other words, will prioritized projects (if several prioritized projects are received during the same timeframe), also be served first-come, first served?

C. PG&E Must Provide Additional Detail on What Types of Upgrades Are Covered under the Cost Offset

In the CMEP Implementation Plan, PG&E proposes to offer cost offsets for "certain upgrades to PG&E's electric distribution system that are required in order to implement the islanding function of a community microgrid, or are deemed necessary by PG&E to ensure safe operations."[14] As currently written, the types of equipment to be covered seem to be limited to equipment that is located on the utility-side of the customer meter. The Joint CCAs request PG&E clarify if cost offsets would also cover line upgrades and/or new facilities or lines that are required on the customer side of the meter to implement the islanding function of the microgrid.

Also, if the operation of the microgrid results in the deferral or elimination of any future planned distribution system upgrades, including replacement of transformers, conductors, capacitors, etc., the Joint CCAs request that the value of these avoided and/or deferred distribution system upgrades be used to offset the cost of the microgrid.

[14] AL 5918-E at 9

2. Customers Must Receive Assurances About Receiving the Cost Offset During Early Stages of Project Development to Reduce Risks

PG&E states in the CMEP Implementation Plan that "cost offset funding will be made available on a first-come, first-served basis to those customers who meet the requirements of the Community Microgrid Enablement Tariff, *including completion of the Microgrid Islanding Study and execution of the Special Facilities Agreement* [emphasis added]."[15] Based on this language, it is the Joint CCAs' understanding that customers will only be guaranteed access to cost offsets *after completion* of the Microgrid Islanding Study and the execution of the Special Facilities Agreement ("SFA"). Both items are rather complex agreements and, as displayed in PG&E's Microgrid and Interconnection Processes flow chart,[16] occur towards the end of the project development cycle. This would lead to significant cost uncertainty on part of the customer. Uncertainty over the costs of a project is a very large hurdle for program participation.

Instead, as it is customary with many customer (incentive) programs, the Joint CCAs strongly recommend that cost offsets can be *reserved* by a customer after the customer meets minimum eligibility requirements for participation in the CMEP (i.e., once the CMET application is approved) and an initial cost estimate for necessary distribution upgrades was established. In fact, PG&E should be required to establish an initial cost estimate for necessary distribution upgrades in the early stages of the WDT/Rule 21 interconnection process so that customers can receive a reservation on the cost offset assigned to their project. This would allow the customer the certainty that no other project may "pass them in line" while they are working on the Microgrid Islanding Study and the SFA, thereby being at risk of losing the cost offset if program funds are running low. If a project ends up not completing the Microgrid Islanding Study and SFA and thereby drops out of the CMEP, reserved cost offsets would be returned to the program and made available to the next customer in line.

[15] AL 5918-E at 10
[16] Id. at 8

3. PG&E Must Explicitly Allow Microgrids to Participate in Grid-Service Programs, Contracts and Service Agreements in Blue Sky Mode

PG&E establishes in section I of the Community Microgrid Enablement Tariff ("CMET") that microgrid resources are eligible to provide distribution services and/or participate in demand side management programs during Blue Sky Mode so long as participation in those programs does not "impede the ability to enable Island Mode, as determined by the Distribution Provider".[17] The same provision exists for the signing of service agreements such as power purchase agreement or other contracts for energy, capacity or distribution services. The Joint CCAs note that it will be essential for microgrid developers and customers to take advantage of these additional revenue streams during Blue Sky Mode to make microgrid projects pencil out financially.

However, the proposed rules are overly vague in terms of what type of program or service agreement may "impede the ability to enable Island Mode". Additionally, the decision is left unilaterally to the utility. For example, many grid services involve day-ahead market bidding and/or scheduling in the wholesale market (e.g., wholesale energy, resource adequacy obligations) or advanced commitment of capacity (e.g., demand response programs). Based on the language currently proposed in section I of the CMET, it is unclear if such a bidding or scheduling commitment would be interpreted by the utility as impeding the ability to enable Island Mode under the CMET.

The Joint CCAs recommend that PG&E clarify this language in the CMET to clearly allow microgrid resources value stacking through the various available programs and services. To enable such participation, PG&E must be required to communicate potential Emergency Events/ Islanded Mode with ample notice to microgrid operators so that operators can adjust their commitments to other grid-service activities appropriately. Such advanced notice is also essential to allow for full charging of the microgrid energy storage system before the Emergency Event/ Islanded Mode.

[17] AL 5918-E, Appendix 4, Pro Forma Community Microgrid Enablement Tariff, at 4-5.

4. Policy-Focused Proposals Made by PG&E in the CMEP Implementation Plan Must Be Further Discussed in Track 2 of the Microgrid Proceeding

While the Joint CCAs don't believe that the following policy issues merit, in and by themselves, a protest to the CMEP Implementation Plan, they should be highlighted as issues that require further discussion (and potential modification) under Track 2 of the microgrid proceeding.

A. The CMET Should Not Be Considered Precedent-Setting for the Development of a Comprehensive Microgrid Tariff

As the Joint CCAs stated in Opening and Reply Comments on the Track 2 Staff Proposal under the Microgrid Proceeding,[18] it is critical that the Commission develop a unified and holistic Microgrid tariff in the Rulemaking. While the Joint CCAs understand the necessity of a tariff proposal that accompanies the CMEP, the IOUs must not be allowed to develop an inefficient and fragmented microgrid tariff structure in the long run. Hence, the Joint CCAs would like to emphasize that the CMET, in its current form, should not set precedent for future development of a holistic community-scale microgrid tariff. Such a holistic microgrid tariff must be developed with proper stakeholder input through the microgrid proceeding, and not through an advice letter filing. The lessons learned from the CMEP/ CMET implementation should certainly serve to inform the development of a holistic microgrid tariff but should not be considered as precedent setting or "the only feasible or reasonable solution".

B. All Cost for Transmission and Distribution Upgrades for Microgrids that Serve a Public Interest or a Critical Need Should be the Responsibility of the Utility

Under the CMEP, PG&E proposes to offset 100% of costs of PG&E owned- and operated distribution equipment, up to a cap of $3 million per project. PG&E adds that "[t]hese are costs that otherwise would normally be the responsibility of the customer requesting the upgrades under

[18] Opening Comments of the Joint Community Choice Aggregators on Track 2 Proposals at p.2; Reply Comments of the Joint CCAs on Track 2 Proposals at p.1

relevant existing tariffs."[19] While the Joint CCAs acknowledges that this position is consistent with current policy regarding distribution system upgrades caused by customer-sited microgrids, it should be noted that there is an open policy question of whether this is the appropriate approach in all instances. For example, if a multi-customer microgrid covers several critical facilities that serve a public good (e.g. police or fire station, community resources center etc.), should there be a cost responsibility with the utility, or ratepayers as a whole, to cover for the required grid upgrades to enable the microgrid? The recently published staff proposal under Track 2 of the microgrid proceeding discusses exemptions from cost responsibility surcharges for certain types of single-customer microgrids. The Joint CCAs believe that the same discussion must be had for multi-customer microgrids and strongly recommend that this matter must be further litigated in the policy track of the microgrid proceeding. Consequently, whichever resolution the Commission finds in regards to cost responsibility for grid upgrades under the CMEP should not set precedent for future microgrid commercialization.

III. CONCLUSION

The Joint CCAs appreciate the Commission's consideration of the recommendations proposed above in regards to PG&E's CMEP Implementation Plan.

Respectfully submitted,

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[19] AL 5918-E, at 9

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S TRACK 3.A COMMENTS ON THE INVESTOR-OWNED UTILITIES' PROPOSED COMPETITIVE NEUTRALITY RULES

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
TRACK 3.A COMMENTS ON THE INVESTOR-OWNED UTILITIES' PROPOSED COMPETITIVE NEUTRALITY RULES

Pursuant to the Amended Scoping Memo and Ruling,[1] the California Community Choice Association (CalCCA)[2] submits these comments on the proposed competitive neutrality rules submitted by Pacific Gas and Electric Company (PG&E)[3] and Southern California Edison Company (SCE)[4] (collectively, IOUs) on September 1, 2020, pursuant to the Amended Scoping Memo and Ruling.[5] The IOUs submitted the proposals in compliance with Ordering Paragraph 24 of Decision (D.) 20-06-002.

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1 R.19-11-009, *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling,* July 7, 2020, at 6.

2 California Community Choice Association represents the interests of 20 operational community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

3 Proposed Competitive Neutrality Rule of Pacific Gas and Electric Company (U 39E) Filed Pursuant to Ordering Paragraph 24 of Decision, Sept. 1, 2020 (PG&E Proposal).

4 Southern California Edison Company's (U 338-E) Proposed Competitive Neutrality Rules, Sept. 1, 2020 (SCE Proposal).

5 R.19-11-009, *Assigned Commissioner's Amended Track 3.A and 3.B Scoping Memo and Ruling,* July 7, 2020, at 6.

I. INTRODUCTION

The competitive neutrality rules proposed by SCE and PG&E respond directly to Ordering Paragraph 24 of D.20-06-002. The Commission determined that such rules are necessary to mitigate "anti-competitive and conflict of interest concerns" related to the solicitation process administered by the IOUs as Central Procurement Entity in procuring local resource adequacy (RA) resources.[6] The Commission intends for these rules to "govern how confidential, market-sensitive information received from third-party market participants during the solicitation process will be protected and what firewall safeguards will be implemented to prevent the sharing of information beyond those employees involved in the solicitation and procurement process."[7]

In general, SCE's Proposal provides a clear and reasonable approach to competitive neutrality. CalCCA finds only one area of concern: the exclusion from the competitive neutrality rules for new generation procurement. CalCCA requests that, absent a plan from SCE as to how these concerns will be addressed, SCE's exclusion of new generation procurement from the competitive neutrality rules should be denied.

PG&E's Proposal lacks the level of detail provided by SCE and requires further development before it can be fully evaluated and adopted by the Commission. CalCCA discusses several modifications in Section III and proposes that PG&E be required to amend the proposed rules to provide greater specificity. CalCCA also recommends that PG&E look to D.12-12-026 and SCE's Proposal for guidance.

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6 D.20-06-002 at 35.
7 *Id.*, Ordering Paragraph 24.

II. SCE'S PROPOSED EXCLUSION FOR NEW GENERATION PROCUREMENT SHOULD BE REJECTED

SCE's rules, while generally sound, include an unjustifiable exemption from the rules for bids received for new generation procurement. SCE explains that these bids "shall not be subject to this competitive neutrality rule because such bids are not considered confidential, market sensitive information that can provide an unfair advantage to SCE's bundled service customers."[8] Beyond concluding that this information would not unfairly advantage SCE bundled customers and that evaluating new generation bids is resource intensive, SCE did not sufficiently explain why information contained in new bids would not be considered confidential.

CalCCA does not believe the proposed exclusion is warranted. All bids, to varying degrees, will contain market sensitive information that is confidential. Moreover, even if all bids were fully made public, the "black box" bid evaluation by the CPE will be opaque to other stakeholders, and determining why the CPE chose one project over another may be difficult. Finally, if the staff of the IOU/LSE, in working with the staff of the IOU/CPE staff, can potentially gain knowledge of CPE solicitations or indirectly influence CPE staff's decision-making, such blurring of the lines between the two sets of staff can unfairly advantage bundled customers in bidding the new resources.

CalCCA requests that, absent a plan from SCE as to how these concerns will be addressed, SCE's exclusion of new generation procurement from the competitive neutrality rules should be denied.

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8 SCE Proposal at 6.

III. PG&E'S PROPOSAL REQUIRES GREATER SPECIFICITY TO ENABLE A FULL EVALUATION

CalCCA appreciates PG&E's efforts to create a structure for ensuring market sensitive information it receives from CPE solicitations does not create a competitive advantage for PG&E's bundled customers. However, CalCCA requests PG&E's proposed competitive neutrality rules provide greater detail than the current high-level proposal. CalCCA believes the Code of Conduct rules created for Independent Marketing Divisions contemplated in D.12-12-036 could provide an example of more detail on how the CPE Procurement Group could be set up.

As a guiding rule, CPE staff should be completely separated from the general PG&E staff, although CalCCA recognizes there will be instances where that is infeasible and impractical (*e.g.,* HR, Payroll). CalCCA requests PG&E provide greater detail on what "other procurement-related capacities within PG&E" functions its CPE Procurement Group staff would perform. Further, CalCCA requests PG&E provide greater detail on which "individuals within PG&E that provide shared administrative services…may obtain information through the CPE solicitation process that is market sensitive."

Lastly, CalCCA requests the "Tools for Effectuating the CPE Neutrality Rule" include an enforcement procedure to ensure on-going compliance in addition to what is already included. The enforcement procedure should include mandated reporting for internal incidents of sharing confidential information as well as an enforcement proceeding process. Again, CalCCA believes the Code of Conduct and Expedited Complaint Procedure in D.12-12-036, and specifically Sec. 8.2 could be used as an example in creating an "enforcement" proceeding process.

The Commission should direct PG&E to amend its proposed competitive neutrality rules. In general, CalCCA requests that PG&E look to SCE's Proposal for guidance in further developing its proposal to enable a full evaluation.

IV. CONCLUSION

CalCCA appreciates the opportunity to comment on the IOUs' competitive neutrality rules and requests that the Commission: (1) absent a plan from SCE to address the concerns raised by CalCCA, reject SCE's exclusion of new generation procurement from the competitive neutrality rules; and (2) direct PG&E to amend its proposed rules to provide greater clarity and specificity, relying on D.12-12-026 and SCE's Proposal for guidance.

Respectfully submitted,

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

Evelyn Kahl

Evelyn Kahl
General Counsel

September 11, 2020

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

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON SECTION 10 OF THE ENERGY DIVISION STAFF PROPOSAL FOR A TRANSPORTATION ELECTRIFICATION FRAMEWORK

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OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON SECTION 10 OF THE ENERGY DIVISION STAFF PROPOSAL FOR A TRANSPORTATION ELECTRIFICATION FRAMEWORK

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC") and the *Email Ruling Resetting Procedural Schedule for Comments on Transportation Electrification Framework Sections,* dated August 4, 2020, the Joint Community Choice Aggregators ("Joint CCAs") submit these opening comments on Section 10 of the Draft Transportation Electrification Framework ("TEF").[1] The Joint CCAs have also reviewed and fully support the opening comments filed concurrently by Peninsula Clean Energy Authority ("PCE") on Sections 9, 10 and 12 of the Draft TEF.

I. INTRODUCTION AND SUMMARY

The Draft TEF recognizes the key role Community Choice Aggregators ("CCAs") play in fostering the adoption of transportation electrification ("TE") in California. At this point in time, CCAs are already the default Load Serving Entity ("LSE") for four million customer accounts in the state, serving over ten million Californians.[2] There are currently 21 operational CCAs in California, and CCAs supplied 44,400 GWh of electricity in 2019.[3] As noted in the Draft TEF, seven additional CCAs are expected to be operational by 2021.[4] Given this level of service by CCAs, the Draft TEF appropriately emphasizes the need for increased coordination between the

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1 The Joint CCAs consist of Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCP"), California Choice Energy Authority ("CalChoice"), Silicon Valley Clean Energy Authority ("SVCE"), East Bay Community Energy ("EBCE"), Redwood Coast Energy Authority ("RCEA"), the City of San José, and Clean Power Alliance of Southern California ("CPA"). The group of CCAs that comprises the Joint CCAs, as defined in this filing, is not identical to the group of CCAs that has filed under this designation in prior filings in this docket.

2 *See* Draft TEF at 132.

3 *See id. See also* https://cal-cca.org/cca-impact/.

4 *See* Draft TEF at 132.

investor-owned utilities ("IOUs") and CCAs in the development and administration of TE programs. The Joint CCAs strongly agree that IOU-CCA coordination must be a fundamental part of TE program deployment.

The Joint CCAs appreciate the time and effort the Commission and its staff have expended on development of the Draft TEF. The Joint CCAs are encouraged that the Commission is exploring the appropriate role of CCAs in accelerating TE, including the possibility of CCAs serving as Program Administrators ("PAs") of TE programs and pilots using funds recovered through customer rates.[5] The Joint CCAs are committed to enabling widespread TE across all customer segments to reduce Greenhouse Gas ("GHG") emissions as well as criteria air pollutants, and have already developed CCA-funded programs in pursuit of this goal.[6] The Joint CCAs look forward to working collaboratively with the Commission, the IOUs, and other stakeholders to advance California's TE efforts, and to further explore ways by which CCAs may capitalize on their inherent advantages at a local and regional level to accelerate TE.

The following is a summary of the Joint CCAs' principal positions and recommendations with respect to Section 10 of the Draft TEF:

- California's TE goals require a multi-pronged approach that enlists both CCAs and IOUs in a manner that maximizes their respective strengths and advantages;
- Given their unique connection to the local communities they serve, and their role as the default LSE in those communities, CCAs are well positioned to design and administer TE programs across all customer segments;
- Other ratepayer-funded clean energy programs provide a reference for how the Commission may authorize CCAs to access customer funds and serve as PAs for TE programs;
- CCAs should be permitted to draft and file: (i) their own Transportation Electrification Plans ("TEPs"), (ii) applications for approval of their own TE programs; and (iii) advice letters for approval of TE pilots;
- With both CCAs and IOUs serving in the role of TE PAs, increased coordination and planning will be essential to ensure that California meets its TE goals;
- TE programs under the final TEF should be funded through distribution rates;
- CCAs should be permitted to access distribution revenue to fund their TE programs and pilots under CCA TEPs.

[5] *See* Draft TEF at 131.

[6] *See* Attachment 1 for a matrix of existing CCA TE initiatives. *See also* Draft TEF at 132 (describing existing CCA TE programs); *see also Administrative Law Judge Ruling Entering Stocktake Into the Record and Seeking Party Comment*, Attachment B (Stocktake of CCA TE and Electric Vehicle Programs as of May 2019).

II. OPENING COMMENTS

Below, the Joint CCAs respond to the stakeholder questions for Section 10.4.

A. CCAs Should Be Permitted to Serve as Program Administrators for TE Programs and Pilots

1. Should the CPUC consider applications from CCAs for approval to develop their own programs, or administer a portion of the IOUs' authorized TE programs using budgets that are recovered through IOU customer rates?

a. *If yes, what is the appropriate role for the CCAs in accelerating TE (i.e. IOU TE program administrator, designer and administrator of their own programs etc.)?*

The Commission should consider applications from CCAs for development of their own TE programs under the TEF. More specifically, CCAs should be permitted to serve as PAs of their own programs and pilots under their own Commission-approved TEP. In this role, CCAs would be independent of the IOUs in the administration of TE programs and pilots, while coordinating closely with IOU TE programs to prevent duplication of efforts. The Joint CCAs describe their proposed assignment of roles and responsibilities, inherent CCA advantages in administering TE programs, coordination between CCAs and IOUs under the TEF, and proposed cost recovery in more detail below.

1. CCAs Should Be Able to Serve as PAs under Future TEPs Rather than Program Implementers

The Draft TEF suggests that each IOU should work with the CCAs in its service territory "to develop a chapter within its TEP that outlines collaboration to meet the State goals, including alignment on program administration, cost-sharing, and developing distinct, non-competitive TE programs."[7] The Joint CCAs are concerned by what appears to be an implicit premise of this statement, namely, that CCAs would be limited to a "contributor" or program implementer role under the IOU's TEPs. Such an assignment of roles would give the IOU final control in determining the role that each key stakeholder, including CCAs, should play. As further discussed below, the Joint CCAs are concerned that a paradigm that simply "fits CCAs under the IOU's TEP" does not reflect the important role CCAs can, and are already, playing in accelerating TE throughout California. Instead, the Joint CCAs propose that CCAs that wish to

[7] Draft TEF at 134.

administer their own Commission-approved TE programs should be explicitly permitted by the Commission to develop a standalone TEP under the Commission's oversight – one that is independent from the IOUs' TEPs.

The Draft TEF suggests that the Commission should "[c]onsider whether IOUs should hire third party administrators through a competitive bid process for any TE programs, and whether CCAs could bid to be an administrator."[8] The Joint CCAs see this statement as inconsistent with how program *administrator* and program *implementer* roles are typically understood under other ratepayer-funded programs. *Program administrators* are generally responsible for defining the details of program design, as well as overseeing program scope and budget. Importantly, PAs are directly responsible to the Commission, both with respect to program outcomes and the overall composition of programs. Alternatively, *program implementers* are typically chosen by a PA through a solicitation process to run a particular program and/or pilot under the PA's oversight. In this case, while the program implementer has some discretion in program design and management, the PA is ultimately responsible for program outcomes, oversees the program scope and budget, and has the direct relationship with the Commission for program oversight and approval. While program implementers can and do serve an important role, the Joint CCAs request that the final TEF clarify that CCAs may serve as PAs, not merely program implementers. CCAs will be able to make stronger contributions to California's TE goals if they can independently scope their own programs – a task reserved for PAs, not implementers of IOU programs. As described in more detail in section 2 below, CCAs are better positioned than IOUs to identify underserved areas and strategically develop programs that are tailored to local needs.

As PAs of TE programs and pilots, CCAs would have the same rights and responsibilities as the IOUs under the TEF. Specifically, CCAs would file TEPs on the same schedule as the IOUs, outlining their strategic approach for the next 10 years.[9] CCAs would also follow the same rules regarding program and pilot approval as the IOUs. For example, as currently envisioned in the Draft TEF, TE PAs would file applications with the Commission for TE program approval and advice letters for TE pilot approval.[10]

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[8] Draft TEF at 135.
[9] *See* Draft TEF at 18.
[10] *See* Draft TEF at 17.

In summary, the Joint CCAs request that the final TEF be clarified to make sure that, under their respective TEPs, the CCAs would operate independently from the IOUs to develop their own, local TE programs and pilots under the Commission's oversight. Such programs would be administered and implemented by the local CCA themselves or could be bid out to third-parties who would implement components of the programs and pilots with CCA oversight. As discussed in section 2, CCAs have unique abilities that can be best utilized in the context of CCAs serving as PAs. By allowing CCAs to serve as PAs, the Commission will be expanding the scope of its resources to most effectively advance TE goals. While program implementers contribute to these goals, allowing CCAs to serve as PAs will more effectively actuate the unique abilities possessed by CCAs.

2. As Local Government Agencies and LSEs, CCAs Have Unique Abilities That Support and Advance TE

CCAs are uniquely positioned to advance key TE efforts, since CCAs are nonprofit public agency LSEs, which are governed by the cities, counties and towns they serve. As such, CCAs possess local knowledge, data, and expertise that enables them to more effectively accelerate TE deployment in the communities they serve. The following paragraphs describe examples of the inherent advantages held by CCAs in administering TE programs under the TEF. The main point to be made in this regard is that these unique abilities provide a rational basis for the Commission to explicitly permit CCAs to serve as PAs.

First, CCAs are uniquely positioned as public agencies. This manifests itself in two principal ways. As public agencies, CCAs can access unique datasets, which enables them to make strategic, informed decisions and provide tailored solutions that will help California meet its TE goals faster and more equitably. For example, CCAs can access California Department of Motor Vehicle registration data, as well as local parcel and building data. This informs identification of gaps, needs, and opportunities by customer segments. In turn, this local lens allows for strategic investment with a local focus, such as more efficient identification of electric vehicle ("EV") charging infrastructure site hosts to serve a variety of driver use cases. Unlike other policy arenas, the greatest efficiencies in EV charging infrastructure deployment come from having a deep knowledge of local needs, and therefore a hyperlocal focus is necessary to maximize the identification and development of EV charging infrastructure. Additionally, CCAs are governed by boards of local elected officials and engage in a public governance process that provides transparency, trust, and acceptance. A CCA's connection to city and county partners, many of whom sit on the CCA's board, also enables the CCA to actively accelerate TE adoption by more effectively addressing barriers such as land-use planning and zoning, parking regulations and enforcement, local building ordinances, streamlined permitting and inspections, and public education.

Second, CCAs are uniquely positioned for local stakeholder engagement. By virtue of the fact that CCAs are public agencies, they take a local approach to providing technical assistance and education where it is needed most across each of their customer sectors (public, residential and commercial/industrial). CCAs are also well suited for collaborating with fellow public agencies and community-based organizations ("CBOs"). This is particularly helpful to ensure training programs and job opportunities expand as light, medium and heavy-duty zero-emission vehicle adoption expands. The Draft TEF notes, for example, how "CCA's wide reach and relationship with their customers provide a potentially important avenue that can help accelerate TE adoption."[11] The formation of strategic partnerships by CCAs has already led to the development of new charging infrastructure to meet the needs of multi-unit dwelling ("MUD") residents and commuters – a need that is most acutely recognized at the local level.[12] It also has resulted in technical assistance and financial support to accelerate fleet electrification for local public agency partners, including, but not limited to, school districts, cities, counties, and transit agencies.[13] Engagement on the local level has also facilitated work with industry-leading think tanks and CBOs to create partnerships and to provide technical support to private sector urban delivery and medium- and heavy-duty fleet operators and fleet users to reduce the regional impacts of diesel emissions in vulnerable communities.[14] These are just a few examples of the

[11] Draft TEF at 132

[12] *See e.g.* PCE's EV Ready Program, information *available at*: https://www.peninsulacleanenergy.com/ev-ready/. MCE's MCEv Charging Program, information *available at:* https://www.mcecleanenergy.org/ev-charging .

[13] For example, Lancaster Choice Energy ("LCE") helped the Antelope Valley Transit Authority become the nation's first fully electric bus fleet by, among other things, providing a special EV rate for electricity supplied by LCE, information *available at:* https://www.lancasterchoiceenergy.com/2019/09/27/lancaster-california-a-choice-location-featured-article-in-business-view-magazine/.

[14] *See e.g.* EBCE's Municipal Fleet Electrification Plans program and Medium- and Heavy-Duty Market Development program, information *available at*: https://ebce.org/drive-electric-business/.

many CCA TE initiatives that are already underway.[15]

Third, CCAs are uniquely positioned with respect to size. The smaller size of CCAs relative to the IOUs allows CCAs to be nimble, quick and flexible in program design and implementation. CCAs can typically develop customer-focused programs quicker than their IOU counterparts and are flexible in adjusting program requirements if the need arises. This can be a great advantage in program development. One example of an innovative program is SCP's demand response program the GridSavvy Community. The GridSavvy Community is built on the premise that customers can be an active solution to help decarbonize communities, and has evolved over the years to include more than 2,900 smart devices such as thermostats, Level 2 EV charging stations, and heat pump water heaters that are capable of responding to grid signals. In addition to typical demand response events that help reduce SCP projected system peaks, Sonoma Clean Power dispatched this "virtual power plant" fleet in August and September to coincide with California Independent System Operator ("CAISO") flex alerts.

Fourth, CCAs are uniquely positioned with respect to TE costs. As non-profit public agencies, CCAs do not collect a rate of return on capital investments and can therefore focus on TE solutions that are strategic and can help avoid costly electrical upgrades whenever possible. Furthermore, CCAs have shown that they are generally able to deploy TE infrastructure at a lower cost than the IOUs. For example, under MCE's MCEv Charging Program,[16] the average cost per installed port is $4,708.[17] As a rough cost comparison, per port costs under PG&E's

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15 Additional examples of current CCA TE initiatives are described in Attachment 1 ("CCA Transportation Electrification Initiatives: Examples of Existing Programs").

16 MCEv is similar to Pacific Gas and Electric Company's ("PG&E") Electric Vehicle Charge Network ("EVCN") program, as they both target workplace and MUD properties and provide a rebate for the purchase and installation of electric vehicle supply equipment ("EVSE"). However, MCE offers charging infrastructure for sites that want to install 2 or more ports per site as well, thereby filling a need that was left by PG&E's EVCN program requirement of 10 or more ports per site. The MCEv program has supported the installation of more than 550 Level 2 charging ports, with an additional 450+ ports still planned or under construction. Since the inception of the program, MCE has increased public Level 2 charging capacity by 40% across its service area, meeting one of the original program goals. More information is *available at:* https://www.mcecleanenergy.org/news/press-releases/mce-installs-550-electric-vehicle-charging-ports/.

17 This cost data is from an MCE internal program report. These numbers represent project costs as of August 31, 2020. These per port costs include hardware, installation (including as needed electric upgrades and parking lot restriping/bollards), and initial contracted networking fees. These project costs are not inclusive of customer or MCE staff time, warranty fees, and permit fees. MCE has kept its per project costs low since 81 percent of its projects completed to-date are 2-6 ports and thus distribution

EVCN program are estimated at approximately $18,000 per port.[18] The demonstrated ability of CCAs to deploy TE solutions in a cost-effective manner will allow any TE program funds allocated to CCAs' TE efforts to go further, and thereby reach more communities in need of EV charging infrastructure.

Fifth, CCAs are uniquely positioned to address market barriers and equity issues. As locally-driven entities, CCAs can serve hard-to-reach, underserved markets in their respective service areas. For example, PG&E has not deployed any EVCN EVSE installations in the entire RCEA service area, as shown in the PG&E EVCN project map.[19] This may be due to the generally high costs associated with deploying projects within the territory, or other incentive structures that ultimately result in this program's failure to serve customers in this region. As a result, RCEA customers pay for the EVCN program without accessing corresponding benefits from this funding. If RCEA were to be allowed to become a PA for TE programs under the TEF, RCEA could develop TE programs and pilots that address local market barriers, thereby increasing equal access to TE programs for all customers.

3. Coordination Between IOUs and CCAs Will Be Necessary to Avoid Duplicative Programs

The Joint CCAs agree with the staff proposal, which recommends that the Commission "[d]irect the IOUs to ensure their TE programs are complementary to, rather than redundant of, CCA TE programs that ***already exist*** in their service territories."[20] However, the Joint CCAs believe that this directive should be expanded so that the IOUs' ***planned*** TE programs also do not overlap with CCAs' ***planned*** TE programs. Specifically, there should be no overlap with programs that CCA PAs commit to developing in their TEPs. To accomplish these directives, it

level upgrades are rarely needed. Of those 17 projects, only 1 required electrical system upgrades. Also, Americans with Disabilities Act ("ADA") costs are lower with smaller projects since most of MCE's program participants have an additional ADA spot that can be converted to EV accessible spots, whereas larger EV charging projects require more than one EV accessible spot and thus incur those associated costs.

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

19 EVCN Resources, EVCN Map, PG&;E, *available at* https://www.pge.com/en_US/large-business/solar-and-vehicles/clean-vehicles/ev-charge-network/program-participants/resources.page.

20 Draft TEF at 135 (emphasis added).

is essential to formally define a coordination process between IOUs and CCAs in the development of the TEPs that clearly outlines each party's roles and responsibilities. As much as is feasible, the Joint CCAs also recommend that IOUs and CCAs should agree upon pre-determined TE programmatic "focus areas" prior to submissions of final TEPs to prevent duplication. Finally, funding should be allocated in a way that ensures that all customers, regardless of which LSE serves them, have equitable access to the benefits of TE programs and pilots. The Joint CCAs elaborate on these concepts in the following sections.

a. CCA-IOU Coordination Process in the Development of the TEPs

The Draft TEF proposes that the IOUs and CCAs should hold roundtable discussions regarding respective roles and responsibilities.[21] Roundtable discussions and coordination are essential, but they must be understood in context. First and foremost, roundtable discussions should not be interpreted as the IOUs holding a more prominent role than CCAs. Hence, the results of the roundtable discussions should not be that the IOUs develop a chapter within their TEP that outlines collaboration with CCAs as proposed in the Draft TEF.[22] Instead, the roundtable discussions should be a forum for formalizing points of understanding about how to integrate the TEPs under development by both IOUs and CCAs. In this regard, these roundtable discussions may be better described as "TE coordination discussions."

The Joint CCAs recommend two principal modifications or clarifications to the roundtable process. First, the Joint CCAs recommend that a third-party be available to facilitate the roundtable discussion, unless all stakeholders agree in advance that a third-party facilitator is not necessary. The Joint CCAs request the option of a third-party facilitator principally because the Joint CCAs believe a third-party facilitator can help ensure that TE coordination discussions are efficient, and that all PAs have a voice in the coordination process. By engaging a third-party, miscommunication, potential biases and competing interests can be more effectively addressed.

Second, the Joint CCAs recommend that the roundtable process be used for long-term planning and coordination. Since CCAs are proposing to submit standalone TEPs, it is necessary to establish a process by which all PAs' TEPs are assessed for meeting the state's overall TE

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21 *See* Draft TEF at 134.
22 *See id.*

goals. To facilitate this assessment, the Joint CCAs envision the following process. As a starting point, both CCAs and IOUs would convene for one (or several) roundtable discussion(s) to discuss a potential delineation of TE "focus areas." (In the next section, the Joint CCAs provide a proposed conceptual framework for delineating CCA and IOU focus areas for future discussion.) These roundtable discussions would occur before either IOUs and CCAs begin drafting their respective TEPs, with the goal of keeping duplication of TE strategies and approaches to a minimum in the development of the TEPs. As a second step, both IOUs and CCAs would then develop draft TEPs. Once the draft TEPs are completed, the parties would then reconvene for roundtable discussions to address areas of overlap or gaps identified among the collection of draft TEPs. Both CCAs and IOUs would then endeavor to address these overlaps and/or gaps, to the extent feasible, in their respective final TEPs. The final TEPs would then be submitted for Commission review and approval as proposed under the TEF.

b. Delineating TE "Focus Areas" Between CCAs and IOUs

The Joint CCAs suggest that, to the extent feasible, IOUs and CCAs should delineate TE programmatic "focus areas" prior to the development of their respective TEPs. The Joint CCAs are confident that gaps or overlap in program coverage can be addressed by clearly defining the universe of core program areas for each PA in advance. While the Joint CCAs acknowledge that it is not an easy endeavor to delineate TE focus areas between IOUs and CCAs, and competing interests may arise in the process, the Joint CCAs are confident that all parties will be able to at least agree on some "principles" or "conceptual delineation" of TE focus areas. In this section, the Joint CCAs make an initial proposal for conceptual delineation. This should be understood as an initial step of CCA and IOU coordination, and the Joint CCAs are open to further discussion and modification of this proposal.

In principle, IOU and CCA roles and responsibilities should be based upon each entity's core functions. The most "natural" distinction between CCA and IOU focus areas is the delineation along geographical boundaries. In other words, the IOUs should be responsible for larger territory-wide and statewide program components, while CCAs would be responsible for regional and local programs. Dividing roles and responsibilities geographically would ensure that the natural strengths for the IOUs and CCAs are appropriately utilized, while also minimizing the possibility for overlapping or redundant programs. As distribution utilities, the IOUs are well positioned to develop and deliver larger "one size fits all" programs across their service areas. As community-oriented local government agencies, CCAs possess natural strengths that enable them to optimize program offerings in ways that are best for the communities and customers being engaged. This inherent local focus enables CCAs to identify and overcome barriers within their service areas at a local and regional level that may otherwise obstruct widespread TE.

For example, after PG&E launched its EVCN program, MCE learned from many of its customers that they would not be able to participate in the program due to EVCN's 10 ports per site minimum requirement. As a result, MCE created its own, self-funded, Level 2 charging program for workplaces and multi-family properties that offered more tailored services for MCE customers, including a 2-port per site minimum requirement, technical assistance, and an incentive bonus for projects powered by 100% renewable electricity.

In addition to the geographic delineation described above, the Joint CCAs propose that TE programs could be delineated between CCAs and IOUs based upon whether they are "grid infrastructure focused" or "customer and community focused." Under this paradigm, the CCA would be responsible for customer and community focused TE activities, including but not limited to:

- Incentives (e.g., charging infrastructure, vehicles, building electrical upgrades)
- Customer-sited EVSE installation (all customer segments, both customer-owned and CCA-owned infrastructure)
- Deployment of CCA-owned charging infrastructure assets
- Technical assistance to various customer segments (e.g., planning and installation)
- Technical assistance to public agencies (e.g., reach codes implementation and Assembly Bill 1236 compliance)
- Customer and community-based marketing, education and outreach ("ME&O")

The respective IOU, on the other hand, would be responsible for "grid infrastructure focused" activities, including, but not limited to:

- Implementing infrastructure upgrades needed for TE adoption, including grid reliability and hardening
- "Grid-sited" programs
- Streamlining interconnection processes
- Developing uniform building standards

Additionally, the Joint CCAs recognize that there are areas, such as fleets, rate design and vehicle-grid integration ("VGI"), in which both IOUs and CCAs may want to administer programs. The Joint CCAs are confident that the potential for overlapping programs can be addressed through the roundtable process, as described above. The Joint CCAs have included as Attachment 2 to this filing a document that further delineates some of the proposed CCA TE focus areas. The Joint CCAs look forward to discussing these conceptual ideas with the Commission, IOUs and stakeholders through future roundtable discussions or other avenues as determined by the Commission.

c. Ensuring Equitable Access to TE Programs for All Customers

It is important to ensure that ***all*** customers, regardless of which LSE serves them, have equitable access to the benefits afforded by TE programs and pilots offered under the future TEPs. The Joint CCAs suggest that, in certain respects, the Disadvantaged Communities Green-Tariff and Community Solar Green Tariff (collectively, the "DAC Community Solar Programs") provides a helpful model for ensuring that all communities are afforded access irrespective of which LSE administers the program.[23] When the DAC Community Solar Programs were adopted, the Commission explicitly allowed CCAs to serve as PAs for the programs in their respective service areas.[24] More specifically, the Commission chose to reserve program capacity for CCAs according to their proportional share of residential customers who live in DACs. In areas where CCAs do not choose to become PAs for the programs, or in areas where no CCA currently exists, the respective IOU is the default PA for the programs and program capacity reverts back to IOUs.

The Joint CCAs recommend that this "first right of refusal" process should be utilized in TEP coordination as well. For the reasons described above, CCAs should have priority with respect to administering programs that fall within their predefined roles/responsibilities (*e.g.*, local and regional as well as customer- and community-focused programs).

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[23] In June 2018, the CPUC created the DAC Community Solar Programs to increase access to solar for residents of disadvantaged communities located within the IOU's service area. These programs were approved in D.18-06-027. On May 30, 2019, Resolution E-4999 approved, with modification, the tariffs to implement these programs. The Joint CCAs recognize that there are key differences between the DAC Community Solar Programs and TE programs under the proposed TEF, not least of which is the role that administrators play in defining the scope and elements of a TE program. For purposes of this section, the Joint CCAs' reference to the DAC Community Solar Programs is intended to focus on how all communities are afforded access irrespective of which LSE administers the program.

[24] *See* D.18-06-027 at 4, 55-56, 87.

d. Establishing a Funding Cap and Allocating Program Funds Between CCAs and IOUs

Implementing scalable measures to advance TE requires a high degree of cost-effectiveness, both for achieving scale, but also to avoid upward pressure on rates, which could increase on-bill costs of energy, both hurting ratepayers and reducing the benefits of electrification. For these reasons, the Joint CCAs would support establishing an overall maximum on funding available to the portfolio of TE programs and pilots proposed by the PAs. The Joint CCAs would be supportive of the concept of a funding cap, so long as the cap established by the Commission is at the scale necessary to meet established TE goals, and commensurate to the objectives within the approved TEPs. Additionally, in order to ensure equitable program funding between all PAs, the Joint CCAs propose that TEPs include a proposed "portfolio budget" that covers all selected program focus areas. These budget levels would be determined through the TEP coordination process.

B. CCAs Should Be Authorized to Access IOU Revenues to Fund TE Programs

> *2. If the CPUC allows a CCA to file applications to receive ratepayer funds to administer TE programs, what funds should be used (e.g. IOU distribution revenue, non-by passable charges, etc.)?*

This question provides an opportunity to comment broadly on the issue of cost recovery, and specifically on issues involving cost recovery by CCAs, as non-IOU (*i.e.*, non-Commission regulated) entities. As described below, the Joint CCAs' primary concern is not with the precise mechanism through which Commission-approved TE costs are recovered (*e.g.*, IOU distribution revenue, nonbypassable charges, etc.), but rather with ensuring that CCAs have equitable access to these funds and that all customers contribute to the funds. As it stands now, the IOUs' TE programs are funded through revenue derived from distribution rates, paid for by all customers. The Joint CCAs generally find merit in recovering costs through revenue derived from the IOUs' distribution rates. However, the Joint CCAs are not opposed to funding TE programs through other rate elements. From the Joint CCAs' perspective, the primary issue to be addressed is not which rate element should be used to fund CCA programs, but rather how should the current inequitable cost-allocation structure be remedied.

As a foundational matter, inequity currently exists with respect to which customers contribute to TE programs. On the one hand, costs of the IOUs' TE programs are recovered through the IOUs' distribution rates, which are paid by ***all*** customers (both bundled and CCA customers alike). On the other hand, CCAs have funded their TE programs using revenue collected through their generation rates, which are ***only paid by*** CCA customers. As a result, CCA customers are currently paying CCA generation rates to support CCA TE programs, while also paying IOU distribution rates to support IOU TE programs. This cost inequity has been acknowledged by the Commission.[25] The Joint CCAs have been willing to use funds from their generation rates to offer TE programs because their programs are responsive to local needs and are consistent with the CCAs' missions. However, the ability to do so is not limitless and must be balanced by the need to maintain competitive generation rates. Therefore, the Joint CCAs greatly appreciate that the Commission is now considering ways to address this cost inequity.

If the Commission allows CCAs to file applications to administer TE programs, as supported above, the current inequitable cost allocation structure must be corrected. As further described below, models exist through Commission orders for forms of funding that, if applied to TE program costs, would correct this inequity – funding that ensures Commission oversight, collaboration with the IOUs, equitable treatment for contributions made by CCAs, and payment of costs by all customers. Under these forms of funding, since CCAs would be offering programs approved by the Commission and under the Commission's oversight, CCAs should be permitted to fund their TE efforts in the same manner and on the same scale as the IOUs.

Below, the Joint CCAs provide additional comments on issues broadly related to cost recovery by CCAs.

1. The Commission Can and Should Utilize Its Broad Ratemaking Authority to Grant CCAs Access to IOU Revenues

The following section serves two interrelated purposes. First, the comments address an issue identified in the Draft TEF about the relevance of CCAs not being explicitly identified in

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25 *See* R.18-12-006, *Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification*, at 12 ("[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 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."). *See also* Draft TEF at 132 ("A significant difference between the CCA and IOU TE programs is the method for how the programs are funded. IOU program costs have largely been recovered through distribution rates. CCAs TE programs, on the other hand, are typically funded through their generation revenue. . .").

the underlying TE statute. Comments on this issue could have been included in the sections above. However, the Joint CCAs place these comments in this section because it appears that the principal concern being expressed is how, absent statutory directive, a non-IOU entity can receive funds derived from an IOU's rates.

Second, the comments in this section describe how the Commission has broad ratemaking authority that has been used in the past to allow access by non-IOU entities to funds derived from IOU rates. Similar to the first purpose, the determining factor in these previous Commission determinations has not been the identification of the non-IOU entity in statute, but whether the non-IOU entity's access to funds will serve a Commission-established goal.

a. Relevance of Explicit Statutory Identification

The Draft TEF states that "[w]hile California statute authorizes a role for CCAs in the administration of energy efficiency programs, it does not authorize a similar CCA administrator role for TE programs."[26] While factually correct, this fact should not be read in isolation and, more importantly, should not prevent either CCA administration of TE programs or CCA cost recovery for Commission-approved programs. The Commission has broad ratemaking authority and, absent explicit directives to the contrary from the Legislature, the Commission is not statutorily restricted in its ability to authorize and allow cost recovery by non-IOU entities for programs that are overseen by the Commission.

Given the Commission's broad authority and its comprehensive oversight of energy-related programs, the courts have liberally construed the Commission's authority. In this regard, the Commission's actions will generally be upheld as long as they are "cognate and germane" to the Commission's regulatory scope and do not violate a specific statutory limit imposed by the Legislature.[27] The Commission has used this broad ratemaking authority multiple times with respect to energy programs administered by non-IOU entities. The Commission has made these determinations after careful consideration of facts and policy as part of the record in a proceeding, allowing for input from stakeholders.

Above, the Joint CCAs have identified various policy and practical reasons why CCAs should be allowed to administer TE programs that are overseen by the Commission. For these reasons, the Joint CCAs believe the Commission should again utilize its broad ratemaking

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26 Draft TEF at 133. *See also* California Public Utilities Code Section 381.1.

27 *See, e.g.,* Decision ("D.")10-12-060 at 5.

authority to grant CCAs access to revenue derived from IOU rates. In doing so, the Commission can rely on similar determinations made in other proceedings, as described below.

b. Similar Determinations Made by the Commission

Below, the Joint CCAs provide examples of energy programs for which the Commission has allowed participation by non-IOUs even though the underlying statute explicitly identified the IOUs. These examples are relevant because the underlying TE statute directs the Commission to ***require*** the IOUs to file TE applications, but is silent with respect to whether the Commission may also ***allow*** CCAs to file TE applications.[28] The examples below reflect the rule described in the previous section, namely, absent express limitations imposed by the Legislature, the Commission can, based on facts and policy considerations developed in the regulatory proceeding, allow non-IOU entities to administer energy programs.

The following is a summary of these examples:

- Public Utilities Code Section 381 authorizes the Public Purpose Program Charge ("PPPC"), which provides funding for numerous energy programs. Although the "electrical corporations" are specifically identified in Section 381, the Commission has repeatedly determined that non-IOUs may administer or participate in programs supported by the PPPC. Of particular note, the Commission determined that local government entities (Regional Energy Networks ("RENs")) may administer energy efficiency ("EE") programs funded by the PPPC.[29]

- Section 2827.1 (added by Assembly Bill 327 [2013]) specifically involves disadvantaged communities ("DAC") tariff programs applicable to the large IOUs, yet the Commission expanded involvement to non-IOUs (CCAs) upon adherence to the Commission's rules.[30]

- Section 399.15 (originally added by AB 970 [2000], later renumbered Section 379.5) authorized funding for the Self Generation Incentive Program ("SGIP") and specifically directed the Commission to allow the IOUs to take action and seek recovery of SGIP program costs. The Commission determined, however, in D.01-03-073 that the San Diego Regional Energy Office ("SDREO") (a nonprofit that has since changed its name to the Center for Sustainable Energy ("CSE")) should administer the SGIP in San Diego Gas & Electric Company's ("SDG&E") service territory.

- Senate Bill 1 (2006) codified the Commission's California Solar Initiative ("CSI"), established by the Commission in D.06-01-024. In D.06-01-024, the Commission authorized a non-IOU administrator (SDREO/CSE) to implement the CSI in SDG&E's

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28 *See* Pub. Util. Code § 740.12(b).

29 *See* D.12-05-015 and D.19-12-021.

30 *See* D.18-06-027 at 87.

service area. The Commission cited the "extensive experience" of SDREO in administering the SGIP in the San Diego region, and other factors.[31]

- AB 2723 (2006) codified the low-income set-aside in the CSI, and established the Multifamily Affordable Solar Housing ("MASH") and Single-Family Affordable Solar Homes ("SASH") programs. Notwithstanding references to the IOUs in the CSI and the legislative digest for AB 2723, MASH and SASH programs are administered by non-IOU entities: CSE and GRID Alternatives.

The examples described above share the same general characteristics: (1) the IOUs are identified in the underlying statute, and non-IOU entities are not; (2) the Commission determined, based on facts and policy considerations in the record, that the energy program would be enhanced by non-IOU entity participation; (3) the non-IOU entity voluntarily submitted to Commission oversight and adherence to Commission-established rules; and (4) the non-IOU entity received cost recovery from funds derived from IOU rates. These characteristics are also present in the current context, and lead to a conclusion that the Commission may authorize funding for CCA-involvement in Commission-authorized TE programs.

2. Allowing CCAs to Access IOU Revenue Is An Equitable Solution

As noted above, the Commission has recognized the inequity with the current cost recovery approach.[32] This is particularly problematic when IOUs' and CCAs' programs overlap, and a CCA customer pays for multiple programs aimed at achieving similar results. By allowing CCAs to pursue cost recovery from revenue derived from the IOUs' distribution rates, which are paid by all customers, the Commission will address this problem. As a result, CCA customers will no longer pay more for similar TE programs, since the Commission's processes will ensure that TE programs are not duplicative and that all customers pay for Commission-approved TE programs.

3. The Commission Has Previously Permitted Non-IOUs Access to IOU Revenue to Administer Energy Programs

As noted above, various examples exist of non-IOU administration of energy programs that are recovered through funds derived from IOU rates. As described in more detail below, there is a common theme among these programs that justifies cost recovery by the non-IOU, namely, the non-IOU entity's experience and influence within the program space will positively

31 *See* D.06-01-024 at 39, 42.
32 *See* note 25, above.

contribute to the overall program. The Joint CCAs believe that a similar justification exists for cost recovery by CCAs in the context of Commission-approved TE programs.

As has been previously stated, the following examples reflect the general rule described above, namely, absent express limitations imposed by the Legislature, the Commission can, based on facts and policy considerations developed in the regulatory proceeding, allow non-IOU entities to administer energy programs. Accordingly, if the Commission determines in this proceeding, based on facts and policy considerations, that CCA involvement in the TE program is beneficial and will positively contribute to the Commission's TE program, then the Commission may allow CCA participation and authorize resulting cost recovery.

a. CSE Administration of SGIP

In D.01-03-073, the Commission adopted the ratepayer-funded SGIP in response to AB 970, which called for more distributed generation and load control.[33] AB 970 provided that the Commission shall "include the reasonable costs involved [in such initiatives]. . . in the distribution revenue requirements of utilities regulated by the commission, as appropriate."[34] While referencing IOUs, AB 970 did not specify the entities that would be PAs in these areas. In D.01-03-073, the Commission decided, pursuant to its own regulatory authority, that the SDREO - a nonprofit that has since changed its name to the CSE - would administer SGIP, via contractual arrangement, for SDG&E's service territory.[35] This grant of authority came in response to party comments that the Commission find entities other than utilities "whose interest[s] [are] more aligned with program success" to administer the SGIP.[36] The Commission noted that the proposal to designate SDREO as a PA "provides us with an opportunity to explore non-utility administration on a limited basis. We believe that such exploration will be valuable, given the concerns raised by parties regarding utility administration in this proceeding."[37] CSE

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33 R.98-07-037, D.01-03-073, at 6.

34 AB 970, Section 7 (adding Cal. Pub. Util. Code § 399.15). Note that Cal. Pub. Util. Code § 399.15 is now codified as Cal. Pub. Util. Code § 379.5. While initially the SGIP was funded through distribution revenue, the Commission approved SDG&E's request to begin funding CSE's share of the program using the PPPC instead of distribution funds in 2017. Thus, CSE's funding source for SGIP is currently PPPC funds. Nevertheless, CSE's administration of the SGIP from program inception through 2017 provides one example where the Commission has in the past permitted a non-IOU third-party to utilize IOU distribution revenues in the administration of a program.

35 D.01-03-073 at 5.

36 *Id.* at 17-18.

37 *Id.* at 18.

continues to be the PA for SGIP in SDG&E's service territory, and is generally regarded as a highly successful PA for this program. In addition to SGIP, CSE also is the PA for CSI.

b. CSE Administration of CSI

Similarly, administration of the ratepayer funded CSI programs by CSE also arose by the Commission's own suggestion in Rulemaking ("R.") 04-03-017. SB 1, which later established the CSI via statute, did not give SDREO or any non-utility entity the authority to administer CSI.[38] SB 1 also did not address or disturb the Commission's determination to authorize non-utility administration of CSI.[39] Still, in D.06-01-024, the decision establishing the CSI, the Commission cited the "extensive experience" of SDREO in administering the SGIP in the San Diego region, and determined that it is "prudent to continue the status quo with existing program administrators, including SDREO."[40] As with the SGIP, the CSI program was initially funded from distribution revenues, including for CSE's administration of the CSI.[41]

c. Regional Energy Networks Involvement in Energy Efficiency Programs

The Commission's previous consideration of RENs has relevance for the Commission's consideration of CCA involvement in TE programs insofar as it reflects another example of a non-IOU entity being allowed to administer a Commission-overseen energy program. RENs are also relevant because they are local government entities, like CCAs, and share many of the characteristics described above that position local government entities to administer local and regional energy programs. The Commission originally introduced the concept of RENs in D.12-05-015.[42] At the time, local government partnerships ("LGPs") were in existence, but the Commission was exploring ways to involve local governments more directly in administering EE programs.

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38 SB 1 (2006) established the CSI via statute. It acknowledged that the Commission adopted the CSI in D.06-01-024, but noted that nothing in the statute should be construed to codify the decision. *See* SB 1, Section 1(a), (b). SB 1 did not address third party administration of CSI.

39 SB 1 (Murray, 2006) established the CSI via statute. It acknowledged that the Commission adopted the CSI in D.06-01-024, but noted that nothing in the statute should be construed to codify the decision. *See* SB 1, Section 1(a), (b).

40 D.06-01-024 at 14, 42, 36.

41 D.06-01-024, pp. 5, 18, Ordering Paragraph 4. *See also* D.06-12-033, Conclusion of Law 28. As with SGIP, the Commission authorized SDG&E to begin recovering CSI funds via the PPPC in 2017 in D.17-08-030, OP 2

42 *See* D. 19-12-021 at 3.

In response to several parties' comments in favor of expanding local government EE programs, the Commission invited proposals from local government entities to form RENs.[43] The Commission was receptive to program administration by RENs in light of parties' comments that RENs would be able to effectively "[p]rovide missing technical resources that will get more projects implemented[,]" include more public agencies in implementation, leverage LGPs, provide centralized regional program management, and tailor programs to local needs and priorities.[44] The Commission noted that local governments' growing experience in EE (through implementation of utility programs or their independent efforts), as well as their access to additional funding from state and federal sources, made them increasingly well positioned to be PAs.[45] The Commission therefore allowed participation by RENs.[46]

At the time of the approval of the first RENs, many local governments had experience administering EE programs directly because of access to grants and other funding from the American Recovery and Reinvestment Act ("ARRA") of 2009.[47] D.12-11-015 sought to capitalize on that experience by continuing successful approaches that were deemed appropriate to be continued. This decision therefore reiterated that increasing local capacity - both in terms of funding and expertise - coupled with local governments' vocalization of their frustration with utility approaches, led the Commission to recognize the value of program administration by local government entities. Just last year, in D. 19-12-021, the Commission authorized the continued operation of existing RENs and invited new REN proposals as business plans to be filed with the Commission.

d. CCA Involvement in DAC Community Solar Programs

AB 327 required the Commission to develop specific alternatives designed to increase adoption of renewable generation in DACs. In D.18-06-027, the Commission adopted three programs to promote solar distributed generation in DACs.[48] Here, the Commission was presented with a request that CCAs become PAs of DAC Community Solar Programs for their own customers and also be eligible for cost recovery. In response, the Commission agreed "with

43 *See id.* at 146-51.
44 *See* D. 19-12-021 at 146.
45 *See id.*at 147-48.
46 *See id.* at 148-49.
47 *See id.* at 4.
48 The DAC Single-Family Affordable Homes and DAC Community Solar Programs.

CCA parties that the Community Solar Green Tariff program [and DAC-Green Tariff program] should be available to both bundled and unbundled customers."[49] 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."[50] As a result, the Commission revised the proposed decision to "address this potential inequity" between IOUs and CCAs, and expressly authorized CCAs to administer their own DAC Community Solar Programs and to receive access to program funding to do so.[51] The Commission also addressed the practical challenges of allowing CCAs the option to offer mandated programs under a universal cost-recovery approach. To ensure program alignment and provide Commission oversight with respect to CCA programs, D.18-06-027 established a Tier 3 advice letter process to ensure that CCA programs abide by all "rules and requirements adopted by [the] decision."[52] Both Clean Power Alliance and MCE have submitted advice letters to the Commission to implement DAC Community Solar Programs.[53] Other CCAs are expected to submit similar advice letters.

e. CCAs Serve as Administrators for EE Programs

In D.14-01-033, the Commission revised its interpretation of the term "administrator" for EE programs to include CCAs, concluding that it is appropriate for CCAs to be EE PAs in the same sense that IOUs are EE PAs.[54] To date, three CCAs have been authorized by the Commission to serve as PAs for EE programs.[55]

CCAs that wish to serve as PAs for EE programs have two options. The first option permits CCAs to submit an advice letter to administer EE programs *just* for the CCA's own customers, using funds that are *only* collected from the CCA's customers. This is generally

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[49] D.18-06-027 at 63.

[50] *Id.* at 87.

[51] *See id.* at 90 ("To address this potential inequity between investor-owned utilities and CCAs and consistent with the change to the program's funding source, the revised APD has been revised to allow CCAs to create DAC-Green Tariff programs funded by GHG allowance revenues.").

[52] *See* D.18-06-027 at 104; Ordering Paragraph 17. The details of this process were further described by the Commission in Resolution E-4999 at 12-19.

[53] *See* Advice Letter CPA 0004-E (December 27, 2019) and Marin Clean Energy Advice Letter MCE 42-E (May 7, 2020).

[54] *See* D. 14-01-033 at 47.

[55] MCE has been serving as a PA for ratepayer-funded EE programs since 2013. LCE received approval in 2018 via Resolution E-4917. RCEA received approval in 2020 via Resolution E-5050.

referred to as the "elect to administer" option.[56] Alternatively, a CCA can submit a formal application to the Commission to administer cost-effective EE and conservation programs that are open to *all* customers, including bundled customers. This is generally referred to as the "apply to administer" option.[57] The latter option permits CCAs to access funds earmarked for EE programs from both their customers as well as bundled customers, since the programs are open to all customers.

4. An Analysis of the Commission's Past Determinations on non-IOU Cost Recovery, Coupled with Determinations Made in this Proceeding, Warrant a Conclusion That CCA Cost Recovery Is Justified

The examples described above provide a framework to analyze the Joint CCAs' request for the recovery of costs for CCAs' TE programs. The orders approving these examples reflect the general rule described above, namely, absent express limitations imposed by the Legislature, the Commission can, based on facts and policy considerations developed in this proceeding, allow CCAs to administer TE programs and seek cost recovery under the Commission's oversight.

First, in the context of TE programs, the Legislature has not specified any limitations on whether the Commission may allow CCAs to administer programs and seek cost recovery. While the Commission has a statutory obligation to direct the IOUs to file TE applications, the Legislature has not limited the Commission's ability to authorize other entities to file TE applications. As reflected in the examples described above, if "cognate and germane" to the overall TE program, the Commission may use its broad authority to invite and allow CCAs to also file TE applications, even though CCAs are not explicitly named in the statute.

Second, like the examples described above, CCAs possess skills and abilities that can contribute to the overall success of TE programs. For example, as described above in the context of the SGIP program, the Commission found that a non-IOU administrator had interests more aligned with "program success" and that inclusion of the non-IOU entity would provide a valuable opportunity to explore non-IOU administration.[58] Likewise, the Commission found, in

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56 *See* D. 14-01-033 at 2. LCE and RCEA have both utilized this alternative "elect to administer" option through a Tier 3 Advice Letter.

57 *See* Public Utilities Code Section 381.1(a)-(d). MCE is the only CCA utilizing this EE option as of 2020.

58 *See* notes 36-37, above.

the context of RENs, that the use of local government entities would provide missing technical resources, leverage LGPs and otherwise aide overall EE efforts. Both of these findings are equally applicable in the context of CCA involvement of TE programs, as reflected in the record for this proceeding.

Third, the examples described above reflect the fact that the absence of statutory inclusion does not hinder the Commission from regulating entities that otherwise are not under the Commission's oversight. In this regard, D.16-10-039 is instructive. In D.16-10-039, the Commission restated its earlier determination that the Commission "does not need rate jurisdiction" over non-traditional entities "to regulate their voluntary participation in" a Commission-administered program.[59] In explaining its earlier determination, the Commission stated that "[b]ecause participation would be voluntary, the Commission concluded that it is not exercising jurisdiction over these non-traditional carriers, but rather, is operating pursuant to the Public Utilities Code to administer the Program."[60] The Commission's holding also had a practical basis, which is equally applicable with respect to CCAs in the context of the TE program, namely "we do not mandate, but rather, encourage … service providers to participate in the [Commission's] Program on a voluntary basis. *** Having seen significant success in the voluntary participation of [other non-traditional entities], we are providing [an] opportunity to participate in the Program on a voluntary basis as well."[61]

In summary, the Commission — in the absence of specific statutory mandates — has authorized CSE to administer the SGIP and the CSI, as well as RENs to administer EE programs. In doing so, the Commission has taken the initiative to recognize that nonprofits and public agencies have the subject-matter expertise and localized experience to administer various ratepayer-funded programs. Since the Commission has been willing to broaden its definition of a PA to entities other than IOUs in other program areas - without an explicit statutory mandate, but in response to party feedback – the Joint CCAs believe that the Commission should similarly exercise its broad authority and do so in the context of TE programs. As California aggressively moves forward with TE efforts, it will be important for the Commission to harness the proven

59 *See* D.16-10-039 at 10 (referencing D.13-05-035 at 15-16).

60 D.16-10-039 at 10 (referencing D.10-11-033 at 135; Conclusion of Law 29.)

61 D.16-10-039 at 11 (emphasis added).

interest and efficacy of public agencies like the Joint CCAs. Allowing cost recovery for CCAs is one key way to support the Commission's overall TE efforts.

III. CONCLUSION

The Joint CCAs thank Assigned Commissioner Rechtschaffen and Administrative Law Judges Doherty and Goldberg for their consideration of the matters discussed herein. The Joint CCAs look forward to continuing to participate in this proceeding in order to ensure that CCA programs are enabled to serve as effective partners in the TE space moving forward.

Dated: September 11, 2020

Respectfully submitted,

/s/ Laura Fernandez

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Joint Community Choice Aggregators

ATTACHMENT 1

CCA Transportation Electrification Initiatives: Examples of Existing Programs

Access to Charging	Incentives and Total Cost of Ownership	Market Education, Coordination & Technical Assistance
100% Renewable Energy for customers, including charging network providers; products approved by CARB, on Zero-CI Lookup Table (EBCE, MCE, SCP)	Used EV Rebates for Low-income Customers (PCE)	Reach Codes (PCE, SVCE, EBCE)
Facilitating CALeVIP Projects with CEC (SCP, MBCP, PCE, SVCE, San Jose; EBCE -2021)	EV Rebates for Low-income Customers (MCE)	Municipal Fleet Electrification Plans (EV, EVSE & other DERs) (EBCE, PCE, SCP)
Deploying Streetlight-mounted Level 2 EV Charging Stations (EBCE)	EV Purchase Discounts (PCE, SCP, San Jose, MCE)	Charging Infrastructure Planning and Deployment TA to multiple customer segments (PCE, SVCE, MCE, EBCE)
Brownfield Reuse for EV Common Charging Yards (MD) and Hubs (LD) (EBCE)	EV Charging Infrastructure Technical Assistance and Rebates for Multi-unit Dwellings and Workplaces (non-CALeVIP; MCE, CPA)	Medium- and Heavy-Duty Market Development (EBCE)
Coordination with Port of Oakland on Common Charging Yards for HD fleets (on Port property; EBCE)	Priority Zone DC Fast Charger Incentives (SVCE, EBCE)	AB 1236: Streamlined EV Charging Infrastructure Permitting (EBCE, MCE)
Coordination with care share provider to increase access to zero emission options at affordable housing properties (EBCE)	E-bike Incentives (PCE, SCP, RCEA)	School Bus Fleet Electrification Analysis (SCP)
	Smart Charging Pilot (PCE)	Regional Recognition/Case Study Promotion (SVCE)
	Demand Response Programs (SCP, CPA)	Innovation Onramp (SVCE)
		TE Clearinghouse (SVCE)
		Member of Joint Agency VGI Working Group (EBCE, PCE)

**Note: This list represents a sample set of programs only. It is not intended to be comprehensive, as it does not reflect all programs currently offered by every CCA.*

CCA Transportation Electrification Initiatives: Examples of Existing Programs (Detail)

CCA	Program Name	Description
Clean Power Alliance (CPA)	Power Response	Enables commercial customers with electric vehicles chargers and energy storage systems to reduce energy costs by modifying usage during times of peak energy use.
East Bay Community Energy (EBCE)	Municipal Fleet Electrification Plans	Roadmaps for local government partners to implement fleet EV, EVSE and other DERs in next 10 years.
	Medium- and Heavy-Duty Market Development	Assessing DMV registration data for service area to understand ecosystem of M/HD fleets; will provide technical assistance to target fleets; coordination with Port of Oakland on charging infrastructure on and off Port property: goal is to establish EBCE's service area as a first-mover market for M/HD goods movement electrification.
	Brownfield Reuse for EV Charging Hubs	Grant award from USEPA (1 of 4 nationally) to assess Brownfields as potential opportunities to deploy shared charging hubs and common charging yards for two use cases (MD fleets and LD drivers).
	2021 Alameda County CALeVIP	Pending incentives for installation of shared L2 and DCFC EVSE; EBCE sole co-funding partner ($15M commitment).
	Reach Codes	Support member agencies in developing and adopting EV Ready reach codes.
	Renewable Energy for Charging Network Providers	Collaboration with charging network providers and other site hosts to serve 100% renewable energy at charging stations. EBCE became the first load serving entity in the state to receive approval from CARB to register its 100% renewable energy product as a certified pathway in the LCFS program.
	AB 1236: Streamlined EVSE Permitting	Provided technical assistance to member agencies and coordinated with Go-BIZ.
	Deploying Streetlight-mounted EV Charging Stations	Collaborating with municipal partner to deploy EBCE-owned Level 2 EV chargers on City owned streetlight poles, leveraging existing electrical capacity and infrastructure for curbside charging.
	Public EV Charging at Faith-based Organizations	Partnering with CBO to collaborate with their members (local congregations) on the development of a plan to deploy publicly accessible EV charging stations at congregations throughout the county.

CCA Transportation Electrification Initiatives: Examples of Existing Programs (Detail)

CCA	Program Name	Description
MCE (formerly Marin Clean Energy) MCE My community. My choice.	MCEv Vehicle Rebate	EV rebate for residents with lower incomes.
	MCEv Charging	Technical assistance & rebate for EVSE @ workplaces & MUDs.
	MCEv Car Sharing	Stackable service with MCEv Charging program to add a shared EV on-site; incentives for low-income MUDs & tenants.
	Zero CI LCFS certified power for Commercial Customers	MCE became the second load serving entity in the state to receive approval from CARB to register its 100% renewable energy product as a certified pathway in the LCFS program.
	AB 1236: Streamlined EVSE Permitting	Provided technical assistance and coordination with member agencies and Go-BIZ.
	Drive Deep Green	Dedicated marketing effort to help EV drivers opt up to 100% renewable power & switch to the EV rate.
	Drive Clean Bay Area	Co-funder of a community-based non-profit initiative to increase EV adoption using behavioral marketing, collective EV purchasing to reduce upfront costs, and concierge support from buying to driving EVs.
Peninsula Clean Energy (PCE) PENINSULA CLEAN ENERGY	Drive Forward Electric	Used EV rebate for residents with lower incomes.
	EV Ready	EV charging station incentive and technical assistance to install 3,500 charge ports.
	Smart Charging Pilot	Residential managed charging, utilizing vehicle telematics. This VGI pilot is in support of PCE's goal of providing 100% renewable energy on a time-coincident basis by 2025 by shifting charging demand off-peak. The pilot is utilizing vehicle telematics as a non-hardware based solution.
	Reach codes	Model reach codes and coordination with local cities to promote EV readiness and building electrification in new construction.
	Community pilots	PCE provided six grants to fund innovative local projects that reduce GHG emissions and benefit the community, including a green fleets pilot with the County of San Mateo.

CCA Transportation Electrification Initiatives: Examples of Existing Programs (Detail)

CCA	Program Name	Description
Silicon Valley Clean Energy (SVCE)	FutureFit Assist: EV Charging	Technical assistance for installing EV charging stations at MUDs and small/medium businesses
	Reach Codes	Support member agencies in developing and adopting EV reach codes
	Priority Zone DCFC	Additional incentives (stacking on CALeVIP) for DC Fast Chargers near certain MUD-dense "Priority Zones"
	SVTEC	Silicon Valley Transportation Electrification Clearinghouse - a collaboration of local stakeholders
	Regional Recognition	Discover and share best practices for installing EV charging
	Innovation Onramp	Semi-annual application cycle to support innovative projects in our communities
Sonoma Clean Power (SCP)	Grid Savvy	Demand Response Program using residential EVSE. SCP is able to dispatch participating EVSE to reduce peak load
	Transit Fleet Electrification	Fleet electrification analysis of the 4 transit fleets operating in SCP territory
	School Bus Electrification	Fleet electrification analysis of the two largest school bus fleets in Sonoma and Mendocino Counties
	DriveEV	Over three years (2016-2018) SCP provided incentives up to $3000 on the purchase of EV's. 1260 EVs were incentivized
	E-Bike Incentive	SCP is planning to provide incentives for up to 1,000 E-bikes beginning in Nov. 2020
City of San José (San José Clean Energy)	CALeVIP	EV Charging station incentives for Level 2 and DC Fast Charging ($14 million)
	Drive Electric San José	Discounts on EVs at 5 participating San José dealerships
	Drive Electric San José Financial Assistance	Educational workshops on EV's and financial empowerment as well as one-on-one financial counseling for low to moderate-income residents

Note: This list represents a sample set of programs only. It is not intended to be comprehensive, as it does not reflect all programs currently offered by every CCA.

ATTACHMENT 2

Proposed CCA Transportation Electrification Program Focus Areas

<table>
<tr><th>Access to Charging*</th><th>Incentives and Total Cost of Ownership (TCO)</th><th>Market Education (ME), Coordination & Technical Assistance (TA)</th></tr>
<tr>
<td>
Home Charging
Level 1 and 2 (L1 and L2) charging for single family homes and multi-unit dwellings (MUD) – market rate & affordable

Workplace Charging
L2 charging for workplaces

Public Charging
Local, data-driven siting of publicly accessible L1, L2, and Direct Current Fast Charge (DCFC) hubs

Fleet Charging
L1, L2, and DCFC charging for public and private sector fleets, including light, medium, and heavy-duty vehicles

* Level 2 and DC fast charging programs will include both LSE and third party owned chargers.

**Access to charging supported through customer EVSE and electric panel upgrade incentives, LSE-owned investments
</td>
<td>
Rate Design, Price Signals, Customer Bill Management & Load Balancing

Rate design to encourage EV adoption
Customer enrollment in 100% renewable energy products to optimize GHG reduction and LCFS credits
Balancing renewables and ramping with residential, DCFC, and L2 workplace charging

VGI (V1G / V2G)

Send DER marketplace signals to qualified vendors participating in VGI pilots/programs
V1G/V2G incentives for managed charging or flexible demand; vehicle to building or local power grid (RES & COMM)
Increase resilience of light-duty, school, and transit fleets; pilot V2G projects
Resilience incentives for customers w/onsite Distributed Energy Resources

Vehicle Incentives

Low-income customers
Rideshare drivers
Group purchase discounts
e-bikes

Financing
</td>
<td>
Market Education

Community outreach campaigns
Rates-focused outreach campaigns
Targeted outreach to low-income customers and fleets in Disadvantaged Communities (DACs) and Low-income Communities (LICs)

MUD TA
Charging infrastructure planning and deployment in affordable MUDs

Fleet TA
EV, charging infrastructure and resilience planning and deployment, including TCO analysis, for public and private sector fleets (light, MD/HD vehicles w/focus on those domiciled and operating in DACs/LICs)

Public Agency TA

AB 1236 charging infrastructure permit streamlining
Reach Code development for EV Readiness and VGI optimization for new and existing buildings
Coordination on Air Quality Risk Reduction & Climate Action Plans

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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)

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION GRANTING
CALIFORNIA COMMUNITY CHOICE ASSOCIATION PETITION FOR
MODIFICATION OF DECISION 19-11-016**

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September 14, 2020

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

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

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION GRANTING
CALIFORNIA COMMUNITY CHOICE ASSOCIATION PETITION FOR
MODIFICATION OF DECISION 19-11-016**

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the August 24, 2020, proposed decision of ALJ Fitch, which *Grants California Community Choice Association Petition For Modification Of Decision 19-11-016* (PD).

CalCCA supports the Commission's adoption of the PD without change. CalCCA's Petition for Modification requested modification of D.19-11-016 in two respects, as the PD notes:[2]

1. To update the QC counting methodology for hybrid resources to the permanent methodology adopted subsequent to the PFM, in D.20-

[1] Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

[2] PD at 3.

06-031, Track 2 of the resource adequacy rulemaking (R.19-11-009).

2. To require, or at least permit, the costs of procurement by the IOUs on behalf of an LSE that opted-out of procuring capacity on behalf of its own customers, to be billed to the LSE directly, rather than to its customers through a nonbypassable surcharge.

The PD fully grants CalCCA's request to apply the final hybrid qualifying capacity counting methodology, adopted in D.20-06-031, to determine compliance with D.19-11-016. While the PD does not *require* the Commission to adopt a methodology to directly bill load serving entities that default to procurement by the investor-owned utility, it modifies D.19-11-016 to make room for the debate now occurring in R.20-05-003.

CalCCA appreciates the Administrative Law Judge's timely response to CalCCA's petition and requests adoption of the PD without change.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

September 14, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues	)))))	Rulemaking 20-05-012

OPENING COMMENTS OF THE JOINT CCAS
IN RESPONSE TO SCOPING MEMO QUESTIONS

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September 16, 2020

On behalf of:
Marin Clean Energy
East Bay Community Energy
Peninsula Clean Energy Authority

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues	)))))	Rulemaking 20-05-012

OPENING COMMENTS OF THE JOINT CCAS
IN RESPONSE TO SCOPING MEMO QUESTIONS

In accordance with the direction provided in the *Assigned Commissioner's Scoping Memo and Ruling* ("Scoping Memo") issued on August 17, 2020 in the above-captioned Rulemaking, Marin Clean Energy ("MCE"), East Bay Community Energy ("EBCE"), and Peninsula Clean Energy Authority ("PCE") (together, the "Joint CCAs") hereby submit the following opening comments in response to Scoping Memo Questions (b) through (k).

I. RESPONSES TO SCOPING MEMO QUESTIONS

Question (b):

> *Should the Commission refine guidance regarding prioritization of equity resiliency budget incentive applications, allowable reimbursable costs or cost control guidance beyond that provided in D.19-09-027 and D.20-01-021? If so, what additional guidance should be considered? Please explain.*

Response to Question (b):

The Joint CCAs strongly recommend that the eligibility criteria for residential low-income customers under the Equity and Equity Resiliency budgets be modified to be based on area-median income ("AMI") *instead of* the current eligibility requirements, which include the requirement that customers' residences be subject to resale restrictions (single-family residences) or deed restrictions (multifamily residences). This modification will better ensure that the Equity and Equity Resiliency Budgets provide the state's most vulnerable customers with resiliency during wildfire events, Public Safety Power Shutoff ("PSPS"), and other grid outages.

Replacing the existing income eligibility requirements with an AMI-based requirement will provide a number of significant benefits. First, it will remove a significant barrier to program participation. The resale/deed restriction requirement has prevented a *significant number* of vulnerable low-income customers who have been impacted by PSPS events or who live in high fire threat district ("HTFD") Tier 2 or 3 zones but do not have the means to purchase energy storage systems from receiving SGIP incentives. This barrier is contrary to the purpose of the Equity and Equity Resiliency programs, is not required by statute, and does not serve any policy goal.

Second, an AMI-based requirement is much more transparent, efficient, and easier to understand than the current income eligibility requirements. The Joint CCAs note that the resale/deed restriction requirement in particular has been the source of significant confusion among potential applicants. An AMI-based requirement would give applicants a clear metric for assessing their eligibility.

Third, adopting an AMI-based income requirement is consistent with a number of recent Commission Decisions demonstrating the Commission's preference for using AMI to determine customer eligibility for income-based programs. This includes, most recently, the *Proposed Decision of Commissioner Rechtschaffen* issued in this Rulemaking, which would adopt an AMI-based income cap (80% of AMI) for single-family residential electric well pump customers to be eligible for the Equity Resiliency budget.[1]

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1 Decision Revising and Clarifying the Equity and Equity Resiliency Budget Electric Well Pump Customer Eligibility Requirements Adopted in Decision 20-01-021, at 7.

To realize these benefits, residential customer low-income eligibility for the Equity and Equity Resiliency budgets should be defined as customers with an annual household income at or below 80% of AMI. This definition should replace the current definition, which includes the unnecessary and burdensome resale/deed restriction requirement. Using AMI to determine whether low-income customers qualify for the Equity Resiliency budget will greatly simplify the eligibility determination process and will help to ensure that vulnerable households that need – but cannot afford – resiliency resources have access to those resources.

Question (c):

> *In response to the COVID-19 pandemic, investor-owned utilities (IOUs) have suspended requirements for applicants to provide a medical certification to enroll in a medical baseline rate and may not require this from applicants for up to a year. Given this, should the Commission consider adopting additional eligibility or verification requirements for medical baseline customers wishing to access the equity resiliency incentives adopted in D.19-09-027 and D.20-01-021? Please explain.*

Response to Question (c):

The Joint CCAs do not have comments in response to Question (c) at this time, but reserve the right to address this matter moving forward in this proceeding.

Question (d):

> *Should the Commission provide any clarifications to the definition of "discrete Public Safety Power Shutoff (PSPS) event" adopted in D.20-01-021 to address situations where customers experience an electricity outage due to an actual wildfire, are at high risk of a future electricity outage, either from a PSPS event or due to an actual wildfire, and/or are de-energized due to an actual wildfire? Please explain.*

Response to Question (d):

It is critical that the Commission clarify and refine the definition of "discrete PSPS event" adopted in D.20-01-021. The current definition is limiting the effective deployment of

Equity Resiliency funding to the customers and communities who need it most and is causing a great deal of confusion for applicants. Even more problematically, it is blocking funding to customers who have been severely affected by PSPS outages or who provide critical services to communities who have been severely affected by PSPS events. This is contrary to the intent of the Equity Resiliency program and should be changed as soon as possible.

The basic purpose of the Equity Resiliency program is to fund resiliency resources for those customers who are at the greatest risk of losing power due to wildfires or PSPS events. In D.20-01-021, the Commission recognized the comments submitted by *many* parties asking that program eligibility be expanded to include not only Tier 2 and 3 HFTDs, but also customers located in areas most likely to experience PSPS outages ("PSPS Zones").[2] However, the Commission was unable to adopt this recommendation because the information necessary to define PSPS Zones was not yet available. Instead, the Commission adopted the "two discrete PSPS events" requirement as a rough proxy for overall PSPS risk. While this was a significant improvement, the current definition still leaves out a number of groups that are at a high risk of wildfire and PSPS related outages.

The Joint CCAs note two main shortcomings of the current eligibility rules surrounding customers at risk of wildfires and PSPS outages. First, customers who have had their power shut off as a direct result of wildfires, but who were not included in a specific PSPS event, do not qualify for Equity Resiliency funding under the current definition. This narrow focus is inconsistent with the basic purpose of increasing the resilience of vulnerable customers most likely to experience outages, and must be updated under future eligibility rules for the Equity Resiliency budget. The Joint CCAs recommend that customers who have been impacted by

[2] At 40.

outages triggered by natural disasters including, but not limited to, wildfires, extreme heat and wind events, or earthquakes, should also be eligible for participation under the SGIP Equity Resiliency program.

Second, the definition of a "discrete PSPS event", as currently defined under the SGIP, does not align with how a PSPS event is defined under other Commission proceedings (e.g. the PSPS/De-energization Rulemaking, R.18-12-005) and must be updated. Under the SGIP, a "discrete PSPS event" is defined as follows:

> For the purposes of SGIP, if the utility de-energizes a customer for safety and then restores power after the weather event has passed, this would count as one PSPS event – whether that PSPS event endured for the customer for only a few hours or some number of days. If power is restored for the customer and another weather event subsequently requires that the utility de-energize the same customer again – whether this occurred days, weeks or months later – this would count as the customer's second PSPS event.[3]

Under SGIP, PSPS events are only considered distinct events if the power to customers is restored between (weather) events. However, in the PSPS Rulemaking and related proceedings, a "PSPS event" is generally referred to as a "weather event".

An example further illuminates the challenges with this distinction in definitions of a "PSPS event" under the SGIP and PSPS proceedings. A significant number of customers in PG&E's service territory received notice of a PSPS event on October 26th, 2019, then a second notice of another event on October 29th. In PSPS reports, submitted under the PSPS Proceeding to the Commission, PG&E calls Oct. 26 and Oct. 29 two PSPS events, referring to "weather events" as PSPS events.[4] PG&E's communications to customers and CCAs also indicated that

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3 SGIP Handbook, page 114.

4 *PG&E Public Safety Power Shutoff (PSPS) Report to the CPUC October 26 & 29, 2019 De-Energization Event* at 2 ("Customers in scope for both events experienced a cycle of either being de-energized and restored for a short period of time, and then de- energized again, or being de-energized and remaining de-energized over the duration of both events").

these were two separate "weather events," which led to many customers submitting applications for Equity Resiliency funding based on this information. However, all applications that relied on this information from PG&E were canceled because they were considered a single "operational event" since power was never restored between the two events. This distinction in definition is highly confusing to customers and applicants, has created significant unnecessary costs and time burden, and has resulted in the unreasonable exclusion of otherwise eligible applicants who are in clear need of resiliency resources.

This example in particular highlights the limitations inherent in using the number of PSPS events that a customer has endured as the sole measure of resiliency needed. A customer who has been through a single long-duration PSPS outage (sometimes in excess of five days) has experienced as much, if not more, disruption than a customer who has experienced two significantly shorter outages. Yet under the current definition, a customer who has experienced a single multi-day outage would not be eligible for funding. The Joint CCAs have included with these comments two letters, identified respectively as Attachment A and Attachment B, which describe challenges faced by customers as a result of PG&E's definition.

The Equity Resiliency budgets should be available for the most vulnerable customers impacted by PSPS and disaster-related outages. Customers who are vulnerable because of their low-income, Medical Baseline enrollment, reliance on a continuous supply of electricity to power medical devices to survive, or reliance on electric well pumps for water; and who are at increased risk of PSPS *or* wildfire/disaster-related outages should not be excluded from receiving funding because of a technicality in the interpretation of the definition of two discrete PSPS events.

The Joint CCAs believe that the easiest and most equitable way to achieve the objective of the Equity Resiliency program is to expand Equity Resiliency program eligibility to anyone who meets the other program criteria and is at an increased risk of wildfire, PSPS, or other disaster-related outages, including the following groups:

- Customers/communities in Tier 2 or Tier 3 HFTDs;
- Customers/communities who have experienced one PSPS event at the time of application to the SGIP;
- Customers who have experienced wildfire or disaster related outage events, defined as planned or unplanned outages due to the destruction, de-energization, or suspension of operation of any transmission or distribution equipment caused by or in response to an ongoing wildfire or other disaster event.
- Customers/communities located in Earthquake Hazards Zones as defined by the California Department of Conservation.[5]

Question (e):

> *Should the Commission further refine the multifamily building requirements adopted in D.19-09-027 to facilitate this customer segment's participation in SGIP? If yes, should refinements include extending eligibility for SGIP for multifamily buildings on a Virtual Net Energy Metering (VNEM) tariff to multi-tenant commercial buildings? If so, what refinements should be considered? Please explain.*

Response to Question (e):

Because of the very high cost of owning a home in California, a significant number of low-income and disadvantaged customers live in multifamily properties. While Virtual Net Energy Metering ("VNEM") allows for the benefits of solar to be shared among tenants of multifamily buildings, it does not provide the resiliency benefits to individuals units. Since solar PV is generally installed for common areas, there is no physical connection to the individual units that would provide recharging for Battery Energy Storage Systems ("BESS") located at the

[5] Available at: https://www.conservation.ca.gov/cgs/geohazards/eq-zapp

units. Under this configuration, the common area may be used as a cooling center or shelter, depending on the type of facilities served by the solar.

However, this is not the only way that solar plus storage can increase resiliency in multifamily buildings. Some multifamily buildings are able to develop systems utilizing onsite solar and storage to provide energy to each unit in the complex during a grid event by way of the Net Energy Metering Aggregation ("NEMA") tariffs available with each utility. To utilize the tariff to aggregate loads, tenants authorize building owners to be the customer of record for all units. All units are then coupled with solar and BESS at the unit level to provide resiliency to the building common areas as well as tenant units. To facilitate this more granular level of resiliency, the Joint CCAs recommend that the Commission clarify that the NEMA tariffs can be applied to multifamily buildings. While NEMA is typically applied to agricultural customers with multiple buildings on a property taking service under a single customer of record, there is no statutory reason for limiting NEMA to this use and current tariffs contain no such limitation. Clarifying the application of the NEMA tariffs will allow a clearer path for building owners to utilize the tariff to optimize their solar and storage systems.

Question (f):

Should the Commission consider revising any SGIP processes or requirements to streamline incentive application, review, approval and other Program Administrator functions? If so, what processes or requirements should be considered? Please explain.

Response to Question (f):

Given the substantial number of SGIP applications PG&E has received over the past several months, and considering the anticipated opening of the residential general market funds in early October and the already long waitlist for that budget category, the Joint CCAs recommend that SGIP program administrators ("PAs") allow the prioritized processing of SGIP applications submitted by certain vulnerable customers. Prioritizing applications submitted from

Medical Baseline customers and/or those who are dependent on electricity for medical needs will provide the greatest public health and safety benefit.

To enact this proposal, the Commission should direct PAs to process all applications from medically vulnerable customers (the Medical Baseline and Life Support customer categories) first, on a first-come, first-served basis. Once those applications have been processed, PAs would begin evaluating all remaining Equity Resiliency applications on a first-come, first-served basis. This will ensure that limited PA resources will be targeted to first assisting those customers who are physically threatened by PSPS events and will enable medically vulnerable customers to move through the SGIP application process more quickly.

The Joint CCA's further recommend that the Commission revise SGIP processes to require that the PAs prioritize corrections to existing applications over new applications. In Sonoma Clean Power Authority's ("SCP's") SGIP Assistance Program, SCP has experienced that applications that receive correction notices during review fall to the bottom of the queue to be reviewed again once corrections are received. This extends the project timeline and creates long periods where an existing project is waiting. If PA's were to prioritize finalizing the review of existing applications over new applications, it would streamline the application process and reduce project timelines.

Question (g):

> *Should the Commission consider the requirements for an IOU or other entity to act as Program Administrator for HPWH incentives? What would preclude an IOU or entity from acting as the Program Administrator? Should any IOU be precluded from acting as Program Administrator for HPWH technologies? If an incumbent IOU is not designated as a Program Administrator, what alternative should be adopted? Please explain.*

Response to Question (g):

Currently, Clean Power SF, EBCE, MCE, PCE, Silicon Valley Clean Energy, San Jose Clean Energy, and SCP implement, or are in the process of designing, heat pump water heater incentive programs. One example of an innovative heat pump water heater program is SCP's GridSavvy Community. The GridSavvy Community is built on the premise that customers can be an active solution to help decarbonize communities, and includes more than 2,900 smart devices such as thermostats, Level 2 Electric Vehicle ("EV") charging stations, and heat pump water heaters that are capable of responding to grid signals. This "virtual power plant" fleet was deployed in August and September to coincide with California Independent System Operator ("CAISO") flex alerts.

In order to maximize the decarbonization potential for heat pump water heaters, it is therefore critical that the program administrator for HPWH incentives under the SGIP coordinate with other non-IOU HPWH programs and initiatives, including those offered by CCAs, to ensure that deployed resources can be integrated into such grid reliability programs. The Joint CCAs request that a formal collaboration mechanism, such as a heat pump water heater working group, be established and that the CPUC outline a process of data transfer such that non-IOU program implementers can easily identify resources within their jurisdictions.

Question (h):

> *How can SGIP incentives facilitate use of EV energy storage systems and/or EVSE to reduce peak load on the grid and/or to charge the storage system when excess electricity is available?*

Response to Question (h):

The Joint CCAs appreciate the Commission's recognition that Electric Vehicle Supply Equipment ("EVSE") and/or Electrical Vehicle ("EV") energy storage systems have a significant role to play in shifting loads and reducing peak loads on the grid, and that SGIP incentives can be utilized to further this goal. If unmanaged, the increased load from California's growing fleet of light, medium and heavy-duty EVs may exacerbate current grid challenges. However, single-direction charging that allows managed charging and flexible, demand-managed EV charging ("V1G") presents a real-time mitigation opportunity that also provides a range of immediate scalable use cases:

- Reducing energy costs to drivers through greater charging control of fleets of EVs, which help reduce on-peak charging and demand charges;
- Cost-effectively maximizing the environmental and societal benefits of EVs by minimizing charging during greenhouse gas ("GHG")-intensive hours on the grid;
- Allowing grid managers to respond to location-specific grid needs, avoiding peaks that may occur when EVs in aggregate simultaneously charge;
- Integrating renewable generation resources and addressing intermittency challenges by charging during periods of peak/excess renewables and discouraging charging during more GHG-intensive periods;
- Paving the way for vehicle-to-building ("V2B")

The scale of these benefits will greatly increase in coming years as the state achieves its ambitious targets to decarbonize the transportation and goods movement sectors. However, realizing these benefits requires more than the "smart charging" that many individual owners of EVs regularly perform through the use of on-board timers and controls. Instead, a large number of EVs must be managed as a fleet and coordinated to respond to grid needs. This requires more centralized and adaptive systems that can work across multiple vehicle types. A functional V1G system requires a number of elements:

- Software, hardware and intelligent systems to manage how and when EVs are charged;

- A fleet of participating EVs;
- EVSE with the capability to participate in V1G, and adequate deployment of infrastructure to ensure driver participation and connection to the V1G system when needed. This includes:
  - Residential EVSE;
  - Publicly available EVSE located at or near workplaces to allow drivers to participate while away from home (a typical workday coincides with peak renewable generation hours);
  - EVSE for public and private light, medium and heavy-duty zero-emission fleets like local government building inspectors and emergency response, transit and school buses, corporate fleets including urban delivery, taxi/rideshare, etc.;

In addition to V1G systems, Vehicle to Grid ("V2G") and Vehicle to Building ("V2B") can provide further local and grid benefits by allowing for two-way energy flow between the EV and the building or grid. These systems have similar benefits to V1G, but by utilizing the vehicle's onboard battery, can also provide resilience benefits. For instance, V2G/V2B systems can increase resilience by providing backup power and/or meet transportation needs during emergency events, particularly when paired with on-site distributed generation and BESS. These V2G/V2B systems can provide these resiliency benefits in both residential applications with a personally owned vehicle and commercial applications with fleets.

Per the most urgent policy recommendations made by the Joint Agency VGI Working Group,[6] the Commission V2G systems represent a near-term opportunity for SGIP incentive eligibility and community benefit. Electric school buses for example can provide emergency backup power, and offer a suite of ancillary services. Other V2G use cases that would benefit from SGIP pilot project incentives include medium-duty commercial trucks (ex. system GHG reduction and renewable integration), residential multifamily charging (system renewable integration and grid upgrade deferral), commercial workplace charging, and rideshare and signal for increasing or decreasing vehicle charging (e.g., system renewable integration, GHG reduction, grid upgrade deferral) in response to grid needs.

There are several immediate ways that SGIP incentives can be used to support the development and adoption of VGI systems (e.g., V1G, V2G, V2B) systems to reduce peak load on the grid, encourage EV charging during the most beneficial times for the grid, and/or provide resiliency benefits.

First, the Commission should create a new SGIP budget category to provide a general SGIP incentive for V1G, V2G and V2B-compatible EVSE systems. This incentive should not be subject to income or geographic/outage risk requirements and eligibility for the incentive should require a multi-year commitment to participate in the local V1G program.

Second, the Commission should expand SGIP budget to explicitly support incentives for battery backup paired with high-use public direct-current fast charger ("DCFC") and fleets. Applicable public fleet examples include but are not limited to transit, emergency response, municipal building inspection and other critical infrastructure use cases (road repair, water,

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[6] *Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group* at 27. Available at: https://gridworks.org/wp-content/uploads/2020/09/GW_VehicleGrid-Integration-Working-Group.pdf

wastewater, refuse, etc.) engaged in providing essential community services like urban delivery and goods movement. To enable this, the Commission should create a new SGIP budget category that provides specific public and private fleets with incentives to install V2G compatible EVSE with battery backup to ensure continuity of service in times of grid outage.

It is important to note that battery backup for all of the use cases above provide critical transportation and goods movement resiliency in both rural and urban areas, and not just in areas designated as HFTDs. Development of the proposed SGIP budget category should not be limited to current Equity Resiliency eligibility criteria. Instead, eligibility should be based on expanded criteria, including customers who have experienced or are at an increased risk of PSPS events or have a role to play in serving the community during disaster-related outages.

Third, the Commission should create a new SGIP budget category to provide public agencies with incentives to install V2G-compatible EVSE chargers with battery backup and generation resources in high risk outage areas, including earthquake zones.

Question (i):

> *How can SGIP incentives facilitate use of EV storage systems and/or EVSE to reduce grid GHG emissions?*

Response to Question (i):

See response to Question (h), above. Managed charging systems can improve GHG emissions on the grid by reducing demand during peak hours, when the grid is using the most GHG-intensive fuels. And as noted in the *Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group* ("Final Report"), V1G technologies allow for fast and flexible response "to event or price signals to provide high-capacity real-time flexibility for serving grid needs such as balancing renewable energy intermittency and supporting intra-day ramping."[7] Such use cases would unlock transportation electrification grid-scale emission benefits that could otherwise be overlooked.

Question (j):

> *How can SGIP incentives facilitate use of EV storage systems and/or EVSE to provide other benefits of electric vehicle grid integrations (as defined in Section 740.16)?*

Response to Question (j):

Public Utilities Code Section 740.16(b)(1) lists five specific benefits of electric vehicle grid integration:

- Increasing electrical grid asset utilization;
- Avoiding otherwise necessary distribution infrastructure upgrades;
- Integrating renewable energy resources;
- Reducing the cost of electricity supply;
- Offering reliability services consistent with Section 380 or the Independent System Operator tariff.

VGI, as discussed above, provides many of these benefits. VGI increases electrical grid asset utilization by allowing the use of excess renewable generation during peak solar periods when excess power might otherwise be curtailed. VGI can reduce the need for distribution upgrades by controlling EV charging to ensure that charging does not occur in a time or manner that would strain the distribution system. VGI supports renewable integration by allowing EV charging during periods of high-renewable generation and avoiding charging during periods of low renewable generation. By taking advantage of low-cost renewable generation during peak

[7] Final Report at 14.

availability, VGI lowers the cost of the electricity supply. By using SGIP to incentivize VGI, as discussed above, SGIP can be used to encourage these benefits.

The Joint Agency VGI Working Group, which involved extensive work by a diverse group of stakeholders including EBCE and PCE, was created to help develop a policy framework to realize the benefits stated in Section 740.6. The Working Group's Final Report lists 92 policy recommendations to further the deployment of VGI technologies. Among those, 23 were identified as short-term policy recommendations that received the "strongest agreement" among the Working Group participants, as defined in the report.[8] The list includes the recommendation/conclusion that V1G technologies should be made eligible for some form of SGIP support to balance the playing field with other distributed energy resource ("DER") technologies.[9] V1G controlled EVSE enabled by SGIP, as discussed above, can provide the following benefits:

- Increased electrical grid asset utilization by allowing the use of excess renewable generation during peak solar periods when excess power might otherwise be curtailed;
- Reduction in the need for distribution upgrades by controlling EVSE to ensure that charging does not occur in a time or manner that would strain the distribution system;
- Optimized renewable integration by encouraging EV charging during periods of high-renewable generation and avoiding charging during periods of low renewable generation;

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8 Final Report at 31.
9 *Id*.

- Low-cost renewable generation during peak availability, which in turn lowers the cost of the electricity supply and the cost to fuel vehicles with domestically produced electricity.

The Joint Agency VGI Working Group's Final Report also reported "good agreement" that there is a "need to clarify the eligibility of battery-backed Direct Current Fast Chargers for SGIP," and that V2G systems should also become eligible for some form of SGIP incentive.[10] Finally, the report concluded there are a wide variety of VGI use cases that can provide value now, or in the very near term ("[there] are 320 different VGI use cases that, for the purposes of this report, should be considered as able to provide value by 2022"). Thus, there is no reason to wait for the final Transportation Electrification Framework ("TEF") to be adopted under Rulemaking R.18-12-006 for new VGI efforts to be proposed and implemented.

Question (k):

> *How can the Commission ensure that EV storage systems and/or EVSE that receive SGIP incentives are used to provide long-term benefits to ratepayers?*

Response to Question (k):

The Joint CCAs agree that it is important for the Commission to take steps to ensure that EV storage systems and/or EVSE that receive SGIP incentives are used to provide long-term benefit to California ratepayers.

For a number of EV/EVSE use cases there is a high degree of certainty that SGIP incentives will provide a long-term benefit to ratepayers. Vehicle fleets, particularly, are long-term investments. Local government agencies for example typically keep and operate vehicles for at least ten years. This period is significantly longer for medium and heavy-duty vehicles

[10] Final Report at 33.

like transit buses and private sector goods movement trucks. As long as the fleet operator commits to install VGI compatible equipment and software, and to participating in the relevant VGI program, the Commission can be confident that the SGIP investment will benefit ratepayers.

The long-term benefits of incentivizing EV fleets extend well beyond the benefits listed above. Public fleets including but not limited to building inspection, social services, emergency response and transit agencies have all said they can't fully electrify their vehicle portfolio without energy storage to ensure they can serve the community in time of grid outage and/or disaster response. For instance, transit buses are a part of local emergency response planning to move people out of the community or to evacuation centers. Additionally, during outages electrified buses may be used to supplement energy storage systems at critical facilities to increase resilience.

Although private sector EV owners may close or relocate, the Commission can mitigate this risk by requiring that SGIP-incentivized VGI related equipment remain in place and participate in the local VGI program for a pre-determined period, and require that the individual EV owner or fleet operator refund part of the SGIP incentive if it cannot fulfill this commitment. As long as the EV remains in state and participates in the VGI program, the full benefits of the public's SGIP investment should be achieved.

/ / /

IV. CONCLUSION

The Joint CCAs thank the Commission for its consideration of these comments in response to the Scoping Memo questions.

Dated: September 16, 2020

Respectfully submitted,

/s/ David Peffer

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On Behalf Of:
Marin Clean Energy
East Bay Community Energy
Peninsula Clean Energy Authority

CALCCA
ADVANCING LOCAL ENERGY CHOICE

September 21, 2020

CPUC Energy Division
Attn: Tariff Unit and Edward Randolph, Director
505 Van Ness Avenue
San Francisco, CA 94102

By email: EDTariffUnit@cpuc.ca.gov

Re: CalCCA and DACC Response to the Joint IOU Advice Letters in response to Decision 20-03-019

Dear Tariff Unit and Mr. Randolph:

Pursuant to General Order 96-B, the California Community Choice Association (CalCCA)[1] and the Direct Access Customer Coalition (DACC)[2] submit this joint response to Pacific Gas & Electric Company's Advice Letter 4302-G / 5932-E, Southern California Edison's Advice Letter 4280-E and San Diego Gas and Electric's Advice Letter 3600-E ("Advice Letters").

Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) (collectively, "Joint IOUs") filed the Advice Letters in response to Decision ("D") 20-03-019, Ordering Paragraph ("OP") 2:

> Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas &Electric Company shall collaborate to submit a joint proposal for bill and tariff changes to show a power charge indifference adjustment line item in their tariffs and bill

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

2 DACC is a regulatory advocacy group comprised of educational, governmental, commercial and industrial customers that utilize direct access for all or a portion of their electrical energy requirements.

> summary tables on all customer bills. Each utility shall submit a Tier 3 Advice Letter by August 31, 2020, to implement the joint proposal by the last business day of 2021. Energy Division is authorized to hold workshops after the filing of advice letters. The proposals must make a showing that the proposed bill and tariff changes are complete and reasonable

The Joint IOUs' proposals contain essentially two changes: (1) refining the definition of PCIA to clarify that all customers pay the PCIA, and (2) adding a PCIA line item to bundled customer bills. These changes are an essential first step towards true comparability for bundled and departed load customer bills. CalCCA urges the Commission to rapidly approve the proposals in the Advice Letters. As described in the Advice Letters, the proposals track those made by CalCCA as part of the Working Group 1 process in Rulemaking (R.)17-06-026, and by AReM/DACC in an early phase of R.17-06-026, and which the Commission endorsed in principle in D.18-10-019.[3]

CalCCA read with concern the language in PG&E and SCE's advice letters foreshadowing a possible delay in implementing the changes due to planned upgrades and changes to their billing system.[4] Given the relative simplicity of the changes here, the fact that these charges already exist on unbundled customer bills and the ample notice to the IOUs that they would need to make such changes (arguably since at least D.18-10-019[5] when the Commission agreed that bill and tariff changes were necessary), we expect the IOUs to meet the Commission's deadline here. Rapid Commission approval of the Advice Letters will doubtless facilitate timely compliance.

The proposals here are a necessary first step towards comparable bundled and unbundled bills. In the language of OP 2, these proposals are "reasonable," but not yet "complete." Even with the changes proposed here, bills remain a confusing customer experience for bundled and unbundled customers alike. More work is needed on both the bills and tariffs to enable customers to make sense of their choices. Accordingly, once these advice letters are approved, the Energy Division should hold workshops as authorized in D.20-03-019 OP 2 to develop a set of further bill and tariff changes during 2021. Again, the purpose of the workshop should focus on the additional changes needed to make bundled customer's bills and tariffs truly comparable to unbundled customer bills. And because certain changes to tariffs require changes to rates, this work should be coordinated with each IOU's GRC Phase 2 Proceeding.[6]

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3 "In D.18-10-019, the Commission has found merit in the tariff revision and bill presentation proposals put forth by AReM/DACC and CalCCA." D.20-03-019, at 21.

4 PG&E Advice Letter 4302-G / 5932-E at 9; SCE Advice Letter 4280-E at 7.

5 D.18-10-018 at 119.

6 PG&E Application 19-11-019; SCE Application 19-08-013; SDG&E Application 19-03-002.

CALCCA
ADVANCING LOCAL ENERGY CHOICE

We thank the Commission for its consideration of this response.

Respectfully submitted,

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Service List R.17-06-026

**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

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON SECTION 10 OF THE ENERGY DIVISION STAFF PROPOSAL FOR A TRANSPORTATION ELECTRIFICATION FRAMEWORK

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September 25, 2020

Attorney for the Joint
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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

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON SECTION 10 OF THE ENERGY DIVISION STAFF PROPOSAL FOR A TRANSPORTATION ELECTRIFICATION FRAMEWORK

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC") and the *Email Ruling Resetting Procedural Schedule for Comments on Transportation Electrification Framework Sections,* dated August 4, 2020, the Joint Community Choice Aggregators ("Joint CCAs") submit these reply comments on Section 10 of the Draft Transportation Electrification Framework ("TEF").[1]

I. REPLY COMMENTS

A. The Commission Has Not Determined That Community Choice Aggregators Are Ineligible to Receive Ratepayer Funding to Administer Transportation Electrification Programs

In opening comments, Southern California Edison Company ("SCE") asserts that "[t]he Commission has already determined that the [Community Choice Aggregators ("CCAs")] are not eligible to receive ratepayer funding for [Transportation Electrification ("TE")] programs."[2] In support of this conclusion, SCE cites an Assigned Commissioner's Ruling from an earlier TE rulemaking ("2016 Peterman ACR").[3]

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[1] The Joint CCAs consist of Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCP"), California Choice Energy Authority ("CalChoice"), Silicon Valley Clean Energy Authority ("SVCE"), East Bay Community Energy ("EBCE"), Redwood Coast Energy Authority ("RCEA"), the City of San José, and Clean Power Alliance of Southern California ("CPA"). The group of CCAs that comprises the Joint CCAs, as defined in this filing, is not identical to the group of CCAs that has filed under this designation in prior filings in this docket.

[2] SCE Opening Comments at 12.

[3] *See* SCE Opening Comments at 12 (citing Rulemaking ("R.")13-11-007, *Assigned Commissioner's Ruling Regarding the Filing of the Transportation Electrification Applications Pursuant to Senate Bill 350* (September 14, 2016)).

An Assigned Commissioner Ruling ("ACR") is issued by a single commissioner and does not reflect a decision by the Commission. [4] Therefore, the 2016 Peterman ACR, while instructive and operative for purposes of initially processing TE applications from the investor-owned utilities ("IOUs"), does not constitute a Commission determination on this issue. If this were not the case, it would be inconsistent for the Commission to specifically ask in this new rulemaking whether the Commission should, based on current circumstances, "consider applications from [CCAs] for approval to develop their own programs…."[5]

As discussed at length in the opening comments of Peninsula Clean Energy ("PCE"), the 2016 Peterman ACR summarily addressed the ***minimum requirements*** of SB 350, and what the Commission is required to do in order to comply with the statute.[6] However, the 2016 Peterman ACR did not address the broad authority of what the Commission ***can*** do as it establishes a final TEF. Moreover, the 2016 Peterman ACR did not address the significant policy considerations that weigh in favor of allowing CCAs to serve as TE Program Administrators ("PAs"). Therefore, contrary to SCE's suggestion, the 2016 Peterman ACR is not dispositive on the issue of whether the current Commission has the authority, based on current circumstances, to permit interested CCAs to serve as TE PAs.

A recent Commission decision underscores this point. In response to the city of Lancaster's request, as a CCA, to receive funding under SCE's Charge Ready 2 program, the Commission directed Lancaster to ***this proceeding*** where "the issue of CCA participation in TE programs and resulting equity concerns [is being addressed] at a more in-depth level…."[7] D.20-08-045 refutes SCE's reliance in this proceeding on the 2016 Peterman ACR, making clear that Commission jurisprudence in this area is evolving and is appropriately set for further examination in this proceeding.[8]

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4 *See, e.g.,* Decision ("D.") 04-05-024 at 6 (referring to an ACR as "an interlocutory ruling, not a Commission decision.")

5 Draft TEF at 131.

6 *See* Opening Comments of Peninsula Clean Energy at 10-12.

7 D. 20-08-045 at 101.

8 *See* D.20-08-045 at 101 ("Future TE proceedings will be evaluated on their merits, and not be bound by the CCA directive in the instant decision.").

B. TE Programs Administered by CCAs Will Be Available to All Customers, Not Just CCA Customers

A number of parties in opening comments incorrectly assumed that TE programs administered by CCAs under the final TEF would only be available to CCA customers.[9] On the contrary, the Joint CCAs propose that TE programs administered by a CCA would be open to ***all*** customers residing in the CCA's service area, including bundled customers. The Joint CCAs envision a model that is similar to the ability of a CCA to "apply to administer" energy efficiency ("EE") programs. In the EE space, a CCA can submit a formal application to the Commission to administer EE and conservation programs that are open to all customers, including bundled customers.[10] The Joint CCAs recommend that, if CCAs are permitted to serve as TE PAs with ratepayer funds, CCA TE programs should be made available to all customers within a CCA's service area.

Pacific Gas and Electric Company ("PG&E") noted in opening comments that "all customers paying distribution rates should have the chance to participate or obtain benefits from TE programs paid for with this funding source."[11] The Joint CCAs agree.[12] Therefore, incorrect assumptions made by other parties to the contrary should be disregarded by the Commission.

C. The Commission Will Have The Authority to Oversee Commission-Approved CCA TE Programs

In opening comments, some parties expressed concern regarding Commission jurisdiction over CCAs. For example, Environmental Defense Fund ("EDF") indicated that they are "more skeptical about the CPUC considering CCA programs for approval, given the lack of clarity over the CPUC's jurisdiction."[13] EDF indicated that this skepticism is based on prior CCA arguments, since "CCAs have argued that they need not necessarily abide by CPUC guidelines, but are rather beholden to their

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9 *See, e.g.,* San Diego Gas & Electric Company ("SDG&E") Opening Comments at 10 ("CCA TE programs funded by distribution rates would only be available to the CCA's customers."). *See also* SCE Opening Comments at 12 ("Allowing CCAs to file applications for programs that are funded by all IOU customers but only available to a subset of those customers who happen to receive generation services from that particular CCA would result in an illegal cost shift.")

10 *See* Public Utilities Code Section 381.1(a)-(d).

11 PG&E Opening Comments at 19.

12 *See* Joint CCAs Opening Comments at 9.

13 EDF Opening Comments at 18.

governing board….”[14] While EDF is correct that CCAs are governed by locally elected boards, EDF’s skepticism is misplaced in this context.

In this proceeding, the Joint CCAs have described a regulatory construct in which CCAs would administer TE programs that are under the Commission’s oversight.[15] Other policy considerations, such as procurement decisions, which are not at issue in this proceeding, should be left solely to CCA governing boards. However, in this proceeding, the Joint CCAs have made clear that CCAs are willing to voluntarily submit to Commission jurisdiction in exchange for the ability to serve as TE PAs. The same has happened in other programmatic areas where CCAs have assumed the role of PA for ratepayer-funded programs under the Commission’s oversight, such as the Disadvantaged Communities (“DAC”) Green Tariff and Community Solar Green Tariff programs, as well as CCA EE programs.[16] In both instances, CCAs voluntarily submit to Commission jurisdiction to administer customer programs, and follow the programmatic rules and requirements applicable to all PAs.

EDF suggests that “any role that [CCAs] play must come with clear safeguards – and an agreement that the CPUC can exercise authority over the administration [of TE programs].”[17] The Joint CCAs agree. The Joint CCAs propose that all TE PAs, including CCAs, would be required to follow the same requirements, such as filing ten-year Transportation Electrification Plans (“TEPs”), submitting applications for TE programs and advice letters for TE pilots, and otherwise adhering to requirements established by the Commission. Given this framework, EDF’s concerns regarding “the outlines of the relationship between the CPUC and CCAs” can easily be addressed in the context of Commission determinations on specific CCA applications and advice letters.[18]

The Vehicle Grid Integration Council (“VGIC”) noted that they are open to the concept of considering CCAs as TE PAs, since “CCAs have a unique and important understanding of local issues and complexities within their service territories,” and VGIC believes “this capability should be

[14] EDF Opening Comments at 18.

[15] *See, e.g.,* Joint CCAs Opening Comments at 23 (citing D.16-10-039 as a leading Commission decision on jurisdiction over non-IOU entities).

[16] The Disadvantaged Communities Green-Tariff and Community Solar Green Tariff programs were approved in D.18-06-027. In D.14-01-033, the Commission revised its interpretation of the term “administrator” for EE programs to include CCAs, concluding that it is appropriate for CCAs to be EE PAs in the same sense that IOUs are EE PAs.

[17] EDF Opening Comments at 18.

[18] *See* EDF Opening Comments at 18-19.

leveraged to advance [vehicle-grid integration ("VGI")] and TE more broadly."[19] However, VGIC also expressed uncertainty about how CCA involvement might work on a practical level, stating that "the Commission has little to no jurisdiction over CCAs in this matter and [CCAs serving as TE PAs] would only be viable if the CCAs did so voluntarily."[20] VGIC's uncertainty can be satisfactorily addressed. First, as noted previously, CCAs would be voluntarily submitting to the jurisdiction of the Commission for the purpose of administering TE programs and pilots. Second, the Commission has previously held that it "does not need rate jurisdiction" over non-traditional entities "to regulate their voluntary participation in" a Commission-administered program.[21] Third, numerous examples exist of non-IOUs administering Commission-overseen energy programs, thereby providing practical guidance for how Commission jurisdiction may be applied to non-IOU entities.[22]

D. Allowing CCAs to Serve as TE PAs is an Equitable Solution

SCE suggests that IOU TE programs are more equitable since the programs "are appropriately funded by all customers because they are available to and benefit all customers, including CCA customers."[23] The Joint CCAs reiterate a point made in opening comments, namely, funding under the TEF should be allocated in a way that ensures all customers, regardless of which load-serving entity ("LSE") serves them, have equitable access to the benefits of TE programs and pilots.[24]

While SCE's statement may be accurate in theory, in practice, IOU TE programs, which are paid for by all customers, do not always benefit all customers, and greater attention is needed to ensure that comparable benefits are provided to all customers. There are specific instances where a community served by a CCA has not received comparable benefits under an IOU TE program. For example, PG&E has not deployed any Electric Vehicle Charge Network ("EVCN") electric vehicle supply equipment ("EVSE") installations in the entire service area of RCEA, as shown in the EVCN project map.[25] As a result, RCEA customers pay for this program without accessing corresponding benefits from this funding.

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19 VGIC Opening Comments at 19.
20 VGIC Opening Comments at 19.
21 *See* D.16-10-039 at 10 (referencing D.13-05-035 at 15-16).
22 *See* Joint CCAs Opening Comments at 17-22.
23 SCE Opening Comments at 13.
24 *See* Joint CCAs Opening Comments at 9.
25 EVCN Resources, EVCN Map, PG&;E, *available at* https://www.pge.com/en_US/large-business/solar-and-vehicles/clean-vehicles/ev-charge-network/program-participants/resources.page.

Additional forms of inequity also exist. CCA customers are currently paying CCA generation rates to support CCA TE programs (which often fill gaps left by IOU TE programs), while also paying IOU distribution rates to support IOU TE programs that may not directly benefit CCA customers.[26] Therefore, permitting CCAs to serve as TE PAs under the TEF is a more equitable solution than the status quo, since CCA customers would no longer be forced to pay twice for TE programs. Under the Joint CCAs' proposal, all customers would pay equally for TE, regardless of their LSE, and all customers would be able to access these TE programs.

E. The Joint CCAs Agree That TE Programs Should Not Be Duplicative

PG&E argues that "[d]istribution ratepayers should not be forced to pay program administration and other costs more than once for similar or the same types of programs."[27] The Joint CCAs agree. The Joint CCAs also agree with Joint Commenters that "collaboration between the IOUs and CCAs will be key to ensure potential program participants are not confused about their eligibilities and that program offerings are not duplicative."[28] This is why the Joint CCAs discussed at length in opening comments a proposal for how CCAs and IOUs can coordinate and collaborate in a manner that minimizes the potential for duplicative program offerings, while also maximizing the inherent abilities of each TE PA.[29] The Joint CCAs believe that the undesirable outcome described by PG&E can be avoided through the coordination process outlined by the Joint CCAs in opening comments.

On a related note, PG&E recommends that "collaboration [should] take place informally without requiring formal CPUC TEP approval, given that CCAs are not subject to CPUC jurisdiction."[30] The Joint CCAs oppose PG&E's request for informal collaboration. It is clear from a review of opening comments that the Joint CCAs and IOUs are not on the same page with respect to the role that CCAs should play under the TEF. Moreover, the Joint CCAs are prepared to provide specific examples of instances where informal collaboration has failed to produce meaningful results. Formal collaboration under the TEF, as proposed by the Joint CCAs, will best ensure programmatic alignment, and will therefore ensure progress is being made towards achieving state goals.

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26 *See* Joint CCAs Opening Comments at 13-14.
27 PG&E Opening Comments at 18.
28 Joint Commenters Opening Comments at 13.
29 *See* Joint CCAs Opening Comments at 8-10.
30 PG&E Opening Comments at 18.

The Joint Commenters offer a helpful view of collaboration efforts aimed at avoiding duplicative efforts. The Joint Commenters indicate that they "see a greater potential to avoid [duplicative program offerings] and instead harmonize programs by allowing CCAs to also draft and submit TEPs alongside IOUs so that the Commission can have a richer view of the full portfolio of programs being proposed."[31] Similarly, the Joint Commenters state that "[a]llowing CCAs to design and implement TE programs in their territories could free up IOU capacity for customized program designs for regions outside of CCA territory, stretching TE efforts further at a time when such efforts must be rapidly accelerated."[32] The Joint CCAs agree. If CCAs are not permitted to serve as TE PAs, there will be less alignment and more fragmentation among TE program offerings, since not all programs would be under the umbrella of the TEF. The Joint CCAs believe that customer confusion will be allayed and resource capacity expanded if all TE programs are coordinated and streamlined under the TEF and TEP processes.

Finally, the Joint CCAs address an example described by PG&E of a supposedly duplicative program offering, SVCE's "Electric Vehicle ("EV") Assistant" program, which PG&E suggests is similar to PG&E's EV Savings Calculator.[33] PG&E argues that creating "such a platform for each CCA, like the potential to duplicate or make 'regionally specific' TE programs, is redundant and an inefficient use of ratepayer dollars."[34] The Joint CCAs are prepared to more fully address this false statement, but for now, the Joint CCAs offer the following abbreviated reply.

First, SVCE currently supports its EV Assistant tool with SVCE generation revenue (*i.e.*, not IOU distribution funds). Any inefficiency in the use of ratepayer dollars in this context is not a result of the regionally-specific nature of the tool, but rather on the current construct that prohibits CCAs from receiving ratepayer funding. Second, any overlap that may exist between the tools is the result of SVCE working to meet specific, observed regional needs. SVCE's EV Assistant tool is intended to provide customers with easily accessible information on EVs in the context the customers' full range of clean electricity choices. In this particular instance, there is value in multiple, similar types of tools, given the observed need for additional marketing, education and outreach. Third, any residual overlap that may exist with reference to SVCE's EV Assistant tool lends support for permitting CCAs to serve as TE PAs under the TEF, since CCAs and IOUs would be required to closely coordinate and align

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31 Joint Commenters Opening Comments at 13.
32 Joint Commenters Opening Comments at 13.
33 *See* PG&E Opening Comments at 19.
34 PG&E Opening Comments at 20.

their offerings through the TEP process. Simply stated, if CCAs are allowed to serve as PAs of future TE programs and pilots, issues of coordination and "redundancy" between IOU and CCA programs would be discussed in preparation of the TEPs and program applications, thereby minimizing overlap between programs.

F. The Joint CCAs Are Relatively Indifferent With Respect to How TE Programs Should be Funded

In opening comments, The Utility Reform Network ("TURN") argues against utilizing distribution revenue to fund TEF programs, and suggests in the alternative that "[a] more fair and equitable cost allocation is for TE program costs to be collected through the Public Purpose Program ("PPP") rate component, which is a non-bypassable charge, to ensure all customers pay equitably."[35] The Joint CCAs see merit in TURN's suggestion, since TURN's analysis demonstrates that "TE program costs do not ***primarily*** support distribution infrastructure upgrades."[36] The Public Advocates Office similarly suggests that TE program costs should be recovered through the PPP.[37] As noted in opening comments, the Joint CCAs' primary concern is not with the precise mechanism through which Commission-approved TE costs are recovered (*i.e.*, IOU distribution revenue, PPP rate component or other non-bypassable charges) but rather with ensuring that CCAs have equitable access to these funds.[38]

G. CCAs Are Better Positioned to Offer End-to-End TE Solutions to Customers Located in Their Service Area

PG&E suggests that they alone should be the end-to-end TE solution provider because of the results of their EVCN program.[39] Three principal factors militate against this outcome. First, it is widely known that customers across all vehicle classes want a concierge service to assist with end-to-end TE project development. PG&E attempts to utilize the fact that EVCN was quickly oversubscribed as a datapoint to demonstrate "strong customer demand for an easy to understand solution that only required customers interact with one entity, PG&E."[40] However, this outcome is not unique to PG&E's EVCN program, and it does not necessarily mean that PG&E, as an IOU, is best-suited to

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35 TURN Opening Comments at 4.
36 TURN Opening Comments at 2 (emphasis added).
37 *See* Public Advocates Office Opening Comments at 7.
38 *See* Joint CCAs Opening Comments at 13.
39 *See* PG&E Opening Comments at 20.
40 *See* PG&E Opening Comments at 20.

serve as that ***single*** solution provider. As supported by the Joint CCAs, CCAs are better positioned to deliver regional results on customer-sited TE projects, while also filling the role of project coordinator on behalf of their community on the IOU grid-side requirements in coordination with the IOU.[41]

Second, the fact that EVCN was "quickly oversubscribed" should not necessarily be interpreted as overall program success. Rather, this fact more clearly suggests that there is pent up demand across PG&E's service area. Simply focusing on the oversubscription may obscure an underlying problem, namely, demand for TE infrastructure is not currently being met equitably. As illustrated by the EVCN project map, some CCA service areas, such as RCEA, do not have any installed EVCN projects.[42] Other CCA service areas, such as SCP and Central Coast Community Energy, have very few EVCN projects. This suggests a geographic inequity, where CCA customers are currently paying for the EVCN program through distribution rates despite being unable to access corresponding benefits from the program. In addition to a geographic inequity, PG&E appears to have prioritized larger projects, with fewer customers, under the EVCN program. For example, there are several sites in the Oakland area that have a disproportionate number of ports being installed through EVCN. Whereas, these ports could have been more proportionally dispersed across a greater number of multi-unit dwellings ("MUDs").[43] The Joint CCAs believe that allowing CCAs to serve as TE PAs, and deliver EVSE programs with a more localized focus, will result in a more equitable distribution of EVSE than what is observed under PG&E's EVCN program.

Third, the EVCN program is not cost effective when compared with local programs that focus on Level 2 workplace and MUD EVSE installations. For example, program costs under the California Energy Commission ("CEC") California Electric Vehicle Infrastructure Project ("CALeVIP") range from approximately $9,000 - $10,500 per port,[44] whereas the per port cost under PG&E's EVCN program is $18,000.[45] It is noteworthy that the CALeVIP program design takes advantage of local partnerships, such as CCAs, which co-fund these investments to deliver results. Moreover, as noted in

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41 *See* Joint CCA Opening Comments at 5-8 and 11.

42 EVCN Charger map *available at*: https://www.arcgis.com/home/webmap/viewer.html?webmap=7f4188377e7547a4b791b5becb1a8c2d&extent=-125.7923,32.3734,-111.9055,40.5997m .

43 *See id.*

44 *See* https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program/california-electric-vehicle/calevip-level .

45 *See* PCE Opening Comments at 9 ("PG&E's EVCN port construction costs are estimated at approximately $18,000/port….").

the Joint CCA's opening comments, MCE's MCEv Charging Program also has a cost per port that is significantly lower than the cost under the EVCN program.[46] In fact, all three IOUs have a higher cost per port in their respective programs than CALeVIP and MCEv Charging, and PG&E is the highest.[47]

Finally, it is worth noting that the Joint CCAs are not alone in recognizing the critical importance of taking a regional and local approach to TE. The CEC's CALeVIP investment program recognizes that, with finite resources, the deployment of TE at a large scale must be broken down into manageable pieces. Regional and local level projects enable prioritization of the highest needs. A local approach also can ensure that funding reaches high-need areas, which may not otherwise secure private investment but are essential to ensuring TE access for all Californians. In sum, these factors support the conclusion the Joint CCAs have been advocating, namely, allowing CCAs to serve as TE PAs, and offer end-to-end TE solutions in their service areas, will enable project deployment at a regional and local level that is strategic, fiscally responsible and results in direct customer and community benefits.

II. CONCLUSION

The Joint CCAs thank Assigned Commissioner Rechtschaffen and Administrative Law Judges Doherty and Goldberg for their consideration of the matters discussed herein. The Joint CCAs look forward to continuing to participate in this proceeding in order to ensure that CCA programs are enabled to serve as effective partners in the TE space moving forward.

Dated: September 25, 2020

Respectfully submitted,

/s/ Laura Fernandez

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[46] *See* Joint CCAs Opening Comments at 7 ("under MCE's MCEv Charging Program, the average cost per installed port is $4,708.)

[47] *See* PCE Opening Comments at 9.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

COMMENTS OF MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY AUTHORITY, CENTRAL COAST COMMUNITY ENERGY, REDWOOD COAST ENERGY AUTHORITY, PIONEER COMMUNITY ENERGY, SONOMA CLEAN POWER AUTHORITY, AND EAST BAY COMMUNITY ENERGY ON POLICY QUESTIONS AND AN INTERIM APPROACH FOR MINIMIZING EMISSIONS FROM GENERATION DURING TRANSMISSION OUTAGES

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September 25, 2020

On Behalf Of:
Marin Clean Energy
Peninsula Clean Energy Authority
Central Coast Community Energy
Redwood Coast Energy Authority
Pioneer Community Energy
Sonoma Clean Power Authority
East Bay Community Energy

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Central Coast Community Energy ("3CE"), Redwood Coast Energy Authority ("RCEA"), Pioneer Community Energy ("Pioneer"), Sonoma Clean Power Authority ("SCP"); and East Bay Community Energy ("EBCE") (jointly, the "CCAs") hereby submit the following comments in response to the questions presented in the September 4, 2020 *Assigned Commissioner and Administrative Law Judge's Ruling Seeking Comment on Policy Questions and an Interim Approach for Minimizing Emissions from Generation During Transmission Outages* ("Ruling").

I. RESPONSES TO QUESTIONS ON EMERGING ENERGY RESOURCE ALTERNATIVES

A. Responses to General Policy Questions

Policy Question 1:

> *Regulatory Simplicity & Ratepayer Maximizing Ratepayer Benefit: Are there duplicative efforts relating to infrastructure hardening and resiliency planning occurring between this proceeding, Rulemaking (R.) 19-09-009, and other proceedings such as R.18-10-007,*

the Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901, or general rate cases, that could expose ratepayers to either duplicative or excessive costs?

Response to Policy Question 1:

It is critical that the Commission closely monitor the investor owned utilities' ("IOU") various outage mitigation, backup generation, and system hardening efforts to avoid duplicative costs. The Microgrids Rulemaking (R.19-09-009), the De-Energization Rulemaking (R.18-12-005), and the Wildfire Mitigation Plan Rulemaking (R18.10-007), and the IOU's General Rate Cases all overlap. For instance, in its 2020 Wildfire Mitigation Plan (submitted in R.18-10-007) and its most recent General Rate Case (A.18-12-009), Pacific Gas and Electric Company ("PG&E") has made significant commitments to reduce the wildfire and public safety power shutoff ("PSPS") outage risk associated with its transmission and distribution ("T&D") system through operational improvements like improved vegetation management and capital investments such as line hardening and installing sectionalization devices.

As these improvements and investments come online, the frequency, scope, and duration of PSPS events should decrease, reducing the need for PSPS outage mitigation measures – including substation-level and smaller-scale temporary generation. IOUs regularly submit progress reports that detail actions and completed tasks. In order to avoid unnecessary expenditures, the Commission must closely monitor the IOUs' progress in implementing their improvements, and in each year should only authorize the amount of temporary generation needed for substations served by higher-risk transmission lines that have not yet been hardened. The Commission should require that the IOUs provide this information on a regular basis and in a usable, detailed format.

In the Community Wildfire Safety Webinars held in the spring of 2020, PG&E described its T&D system upgrades in general terms (for instance, stating that they will install a certain number of sectionalization devices or harden a certain amount of line miles in a certain county), but has not been forthcoming with the detailed information necessary for the Commission and stakeholders to understand the impact of these T&D upgrades on predicted outage frequency and the need for mitigation measures for specific substations and circuits over the next several years. As just one example, PG&E had promised to upload information about the exact location of sectionalization devices, affected circuits and customers, to the PSPS data portal by July 2020. To the Joint CCA's knowledge, this information is still not readily accessible via the portal despite the fact that we are in the midst of the 2020 fire season. Without this information it is difficult to predict which, and how many, customers will lose power during a PSPS outage, which in turn makes it difficult to determine how much backup generation may be needed to mitigate a given outage.

The Commission should be particularly vigilant regarding any IOU proposal to make long-term fossil-fueled generation investments or install permanent fossil fueled generation to mitigate PSPS outages, as these investments will likely be rendered unnecessary by IOU efforts to improve T&D system safety and reliability. If an IOU advocates for permanent generation mitigation, the Commission should require disclosure of the unsurmountable obstacles to grid hardening that make the permanent back-up generation necessary, and a detailed analysis of why those obstacles cannot be overcome.

The crossover and overlap in proceedings and advice letters that touch on aspects of microgrids from data access to interconnection to types of resources and more, creates the potential for duplicative rulings or, more critically, contradictory outcomes. Tracking all of the proceedings in which IOUs have introduced, for Commission consideration, microgrid associated issues is daunting. To allow the Commission to better track and follow where pivotal positions are pending, the CCAs recommend the Commission direct each IOU to provide a table with their submissions listing the proceeding, the track, and the microgrid-associated issue that may be acted upon. The reference table could help the Commission to avoid overlaps or conflicting Decisions.

<u>Policy Question 2</u>:

> *Energy Resource Cost Effectiveness & Reliability: What fuel and technology resources should the Commission consider, as preferred solutions that reduce reliance on diesel for providing power during transmission outages?*
>
> a. *Discuss the costs and benefits for each of the proposed resources;*
> b. *Discuss the cost implications for each of the proposed resources at utility scale;*
> c. *Discuss the greenhouse gas (GHG) reduction benefits for each of the proposed energy resources;*
> d. *Discuss any constraints or adverse local community impacts the proposed energy resources present;*
> e. *Discuss the availability of alternative diesel fuels for each of the proposed energy resources (including whether in-state procurement is feasible) such as natural gas, renewable natural gas, biodiesel, and renewable diesel. Include impacts such as in-state procurement versus out of state procurement, and the need for proximity to other infrastructure (for example, a gas line);*
> f. *Discuss the quantity and capacity available of the proposed alternative fuel resources that can be readily deployed in 2021;*
> g. *Discuss whether these proposed energy resources have been used for electric utility reliability and/or resiliency in the context of natural and/or man-made disasters. This discussion consider should consider population size, demographics, and scale comparable to that of California;*
> h. *Discuss any land acquisition needs including requirements for CEQA review and use permits including authority to construct and permits to operate by air pollution control districts;*
> i. *Discuss any durability requirements that may need to imposed to ensure that a resource can withstand extreme conditions; and*
> j. *Discuss the portability and deployment of the resource and the number of hours of notice necessary to fulfill reliable deployment for immediate customer use? Alternatively, does the resource require permanent installation?*

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

The CCAs do not have adequate information to provide technology-specific answers to the Commission's questions. However, other intervenors in the docket have consistently identified various technologies that can meet the power needs of microgrids – from rooftop solar plus storage powering a single home, to fuel cells powering aggregations of customers, to natural-gas powered internal combustion engines that can support substation loads, to just name a few. The CCAs believe that some of these technologies may be adequately scalable and mobile to serve as temporary generation at the neighborhood or substation level, and to reduce the need for diesel temporary generation during PSPS and other outages. The CCAs encourage the Commission to not lose sight of the state's long-term goals related to GHG and criteria pollutant emissions during this short term, albiet very challenging, situation. The CCAs recommend that the Commission formally adopt the following requirements and principles to guide all temporary generation resource selection – both substation-level and smaller-scale, distribution-connected temporary generation.

First, while party comments may provide useful insight, ultimately the market will provide the best information regarding the price, benefits, viability, and scalability of available temporary generation options. The Commission should order the IOUs to issue multiple all-source solicitations for both substation-level and distribution-connected temporary generation, and these solicitations should be overseen by Commission to ensure that they provide adequate information and are otherwise reasonable.

The CCAs stress that the IOUs bear the responsibility to address the current gaps in information regarding non-diesel temporary generation alternatives. The IOUs are in a far better position than either the Commission or the commenting parties to identify and explore alternative (non-diesel) options for providing temporary generation to safe-to-energize substations during transmission outages. This problem is particularly apparent in the context of PG&E, the IOU facing the most dire situation related to PSPS events. PG&E operates the T&D systems in question, and PG&E is responsible for the PSPS outages that temporary generation microgrids are intended to mitigate. Most importantly, PG&E is the only party in a position to engage with the market, solicit bids, and holistically assess all available temporary generation options.

It is vital that PG&E and the other IOUs pursue all options and make extensive efforts to share information with other entities who can help design solutions for energy consumers. The CCAs ask the Commission to direct PG&E to present Commission with a proposal that places first priority on preferred resources that may be usable as temporary generation (i.e. solar and storage and fuel cells) and preferred resources that may be able to reduce substation load and thus the need for temporary generation (i.e. behind the meter ("BTM") solar and storage, energy efficiency, and demand response). The CCAs—and other stakeholders—are prepared to help address energy consumers' needs and propose solutions, but require a comprehensive data-driven request seeking alternatives to diesel temporary generation.

A serious attempt to explore all temporary generation alternatives would require IOU solicitations that provide: 1) enough information to allow vendors to develop actionable proposals; and 2) reasonable, transparent criteria for bid/technology selection. For instance, in this docket, the Joint CCAs have conveyed that a number of CCAs may be interested in developing and deploying their own resources that may reduce the need for IOU-provided temporary generation. Such resources include, but are not necessarily limited to, CCA-developed distribution-connected microgrids and targeted deployment of CCA-procured or incentivized preferred resources, which would reduce the substation load that would need to be served by IOU temporary generation. [1] However, in order to pursue such resources, the CCAs need more technical data, including, but not limited to, information about the circuits and substations that are "otherwise safe to operate," the load profiles for these circuits and substations, and relevant information regarding line capacity and interconnection requirements. To develop robust non-diesel temporary generation proposals, vendors would also likely need this information.

While PG&E did run a "Clean Temporary Generation Technology" Request for Information ("RFI") in December 2019, this initiative cannot be considered a serious attempt for soliciting alternatives to diesel microgrids at substations. First and foremost, the fact alone that the initiative was run as an RFI, not a solicitation, shows PG&E's reluctance to truly pursue diesel alternatives. Second, numerous stakeholders submitted non-diesel proposals in response to PG&E's December 2019 RFI. In response to the RFI, PG&E provided only limited explanation as to why these proposals were rejected. For example, PG&E states in its Supplemental Testimony from April 1, 2020 that "mobile natural gas responses meet key operational requirements related to load and power duration, but may pose fueling logistics challenges."[2] PG&E did not elaborate on these *potential* fueling challenges nor did it provide an assessment of how easily these challenges could be overcome. Similarly, PG&E's claims regarding the lack of safety certifications and its preference for "turnkey solutions" are vague, and it appears that these hurdles that can be easily overcome through increased collaboration facilitated by an additional solicitation in tandem with further data.

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1 *See*, Opening Comments of the Joint CCAs on Track 1 Proposals at 2-5.

2 PG&E Microgrids and Resiliency Strategies, Supplemental Testimony from April 1, 2020, 3-18 at p.107. This supplemental testimony was not accepted into the record of the Proceeding by the Commission but still provided valuable information to stakeholders about PG&E's microgrid initiatives.

Second, in selecting temporary generation resources (substation-level or distribution-connected), the IOUs should be required to follow the Commission's loading order – give first priority to energy efficiency, then low-emissions and zero-emissions generation resources, and then meet remaining need with fossil-fueled resources. To the extent IOUs do procure fossil-fuel based temporary generation, that generation equipment should either be able to operate with zero-carbon fuels, or have a clear and cost effective path to operate with zero-emissions, in order to minimize long term costs to the state and to achieving a zero carbon generation portfolio. For For fossil-fueled generators, priority should be given to lower-emitting natural gas generators, particularly those fueled by renewable natural gas. Diesel generators should be given lowest priority and should only be used to fill in any remaining gaps. If diesel generators are being deployed in the future, PG&E must focus on using clean biodiesel, preferably sourced as locally as possible.[3]

While some solutions preferred by the loading order like energy efficiency are not stand-alone temporary generation solutions, they can reduce the amount of temporary generation that a substation needs during a transmission outage. The Commission should require that the IOUs: 1) consider these solutions along with temporary generation resources; 2) include all information necessary for the development of both temporary generation and load-reduction solutions as part of their temporary generation solicitations.

Third, the IOUs should be required to use biogas/landfill gas in lieu of natural gas for temporary generation if feasible. The CCAs see landfill gas as an increased option under AB 1383 as biogas/landfill gas gives the Commission an opportunity to address two state priorities by directing IOUs to evaluate biogas options. This requirement is consistent with existing

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3 For example, there are several clean diesel facilities being developed in Contra Costa County that will be sourcing restaurant grease and other related supply streams to create clean diesel.

statements and commitments from the IOUs, including PG&E's statement in its December 2019 DEGEMS Request for Offers ("RFO") indicating that if entities provided natural gas solutions PG&E would attempt to use renewable natural gas for these resources.[4]

Fourth, to the extent that the IOUs need to rely on diesel backup generation, they should be required to use clean biodiesel instead of fossil diesel generation whenever possible. To ensure that the IOUs are meeting this requirement, the Commission should independently assess and monitor available biodiesel supplies and independently verify that the IOUs are utilizing all available biodiesel.

Fifth, the CCAs urge the Commission to adopt a clear definition of what qualifies as "temporary generation." The IOUs should not be allowed to use "temporary generation" as a cover for the deployment of semi-permanent or de-facto permanent generation assets. This is particularly a concern the substation-level, which (generally) will require larger-scale backup generation resources. The Commission must require that all temporary generation resources are only to be operated during outage conditions, and must be mobile and rapidly deployable and re-deployable. Generation resources that require multiple days to set up or take down should not qualify as "temporary generation."

Policy Question 3:

> *Cost Implications: What weight should the Commission give to cost when weighing the need to transition to preferred resources for resiliency? How should alternatives be evaluated for their costs and benefits? How should those costs be allocated and collected?*

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4 *See*, PG&E, 2019 System Reliability Request for Offers, Version 1 – Posted 12/11/2019 at 6-7 (stating: "If a Project consists of a generation technology that utilizes natural gas fuel, PG&E will provide pipeline quality natural gas to the Project, as well as the delivery of an equivalent volume of renewable natural gas ("RNG") to PG&E's gas pipeline transmission and distribution systems consistent with the requirements for new resources in the Decision").

Response to Policy Question 3:

When considering the need to transfer to preferred resources for resiliency, the Commission must consider a number of factors, including cost. The first, overriding consideration must be protecting health, safety, and welfare of the public. This is achieved by: 1) ensuring that PSPS events are only called as a last resort; 2) ensuring that the IOUs rapidly and efficiently achieve system safety through operational improvements and system safety upgrades; and 3) mitigating the impacts of unavoidable outages, including through the provision of backup generation. As part of this analysis, the Commission must also consider the health and safety impacts of temporary generation – including the health impacts of local emissions from fossil generation and any potential fire risk associated with operating temporary generation.

Second, and subordinate to the overriding goal of protecting the public health and safety, the Commission should also weigh the following considerations:

- Cost reasonableness.
- Greenhouse gas emissions reductions.
- Minimizing local impacts, including noise, construction, traffic, and local emissions impacts.
- Minimizing impacts on disadvantaged and other vulnerable communities and supporting social equity.
- Providing temporary generation options that are consistent with local values and preferences.

All of these considerations should be weighed in a multi-factor balancing test.

B. Responses to Alternative Resource Proponent Questions

Proponent Question 6:

> *Customer Solar and Storage: Should the Commission consider alternative energy resources that involve centralized management of behind the meter installations of customer solar and storage as a near-term alternative to deploying temporary diesel generation at the substation level? Why or why not? What is the estimated time and uncertainty related to customer adoption of residential solar and storage that could be centrally managed for the purpose of serving all customer load associated with the same substation? What is the basis for these estimates?*

Response to Proponent Question 6:

The Commission should consider alternative energy resources including behind-the-meter ("BTM") installations as near-term, quick-to-deploy mitigation strategies. The CCAs submit that the Commission must consider alternative resources in this context based on: (1) the numerous statutes that require the deployment of clean generation resources and the numerous Commission policies implementing these requirements; (2) the Commission's cost reasonableness mandate, which favors the minimization of distribution system costs (non-wires alternatives); and (3) the SB 1339 directive that the Commission clear a path to microgrid commercialization. Modest incentives to support the addition of battery storage during the installation of BTM solar can lower ratepayer costs by harnessing private capital already being deployed, and the targeted deployment of BTM solar and storage in "safe to energize zones" can significantly reduce the amount of temporary generation needed to keep those circuits and substations energized during PSPS and other outages.

The CCAs do not look at the tradeoff between temporary diesel generation and renewables plus storage resources as an either/or situation. Rather, the focused utilization of temporary fossil-fueled generation can give stakeholders the breathing room to develop a more holistic response that utilizes the full suite of clean technologies available to mitigate outages while reducing the impacts associated with fossil-fueled temporary generation. As noted above, the use of fossil-fueled generation is not consistent with state policies like the Commission's loading order and creates health impacts that must be avoided in the longer term. Targeted programs grounded in accurate, granular data can produce outcomes that are consistent with state policy, advance collective goals of supporting clean generation technologies, and minimize the use of fossil fueled generation, while also moving us toward meeting SB 1339 goals regarding the commercialization of microgrids.

Proponent Question 7:

> *Critical Loads Microgrids: Should the Commission consider alternatives to substation-level temporary generation that focus on serving a small segment of critical loads in lieu of energizing all substation load? (Note: Such an approach would leave some safe-to-energize customers without power.)*

Response to Proponent Question 7:

As a practical matter, citizens are going to continue to experience outages stemming from de-energization of the T&D system.[5] Poor maintenance of utility infrastructure, lack of integrated planning, and a deficit of policies that support efficient and integrated deployment of distributed energy resources ("DERs"), have led us to a situation that will take years of consistent vision, effort, operational improvements, and T&D system upgrades to remedy. Until we achieve greater grid resilience, de-energization will be an unfortunate feature of the system. For these reasons, many CCAs have worked closely with their communities to identify and support critical load backup supply to mitigate the impacts of IOU shutoffs. Where such CCA programs are not available, or funds have been exhausted, IOU efforts to prioritize critical facilities and vulnerable customers who need energy for medical needs are reasonable. However, we must not lose focus on the holistic solutions needed to meet the moment. Any reduction in

[5] It must be noted that utility customers located in high-fire threat districts level 2 and 3 will certainly be de-energized during PSPS events.

the scope, damage, and duration of outages caused by PSPS events in the near-term is an improvement over the status quo.

II. RESPONSES TO QUESTIONS ON PROPOSED INTERIM APPROACH

Interim Approach Question 1:

> *Do you support the proposal for how the Commission can minimize the use of diesel to serve substation loads in 2021 and 2022? Please respond with a "yes" or a "no" and discuss your reasoning. If you do not support this proposal, provide an alternative proposal that minimizes the use of diesel for energizing substations.*

Response to Interim Approach Question 1:

The CCAs generally support the proposed Interim Approach. The question before the Commission is not a binary one of whether citizens should endure PSPS events for the coming decade or tolerate diesel generators in their communities. The Commission should recognize that the ideal solution will be informed by citizen preferences and grid conditions on a location-by-location basis. In this light, the CCAs believe that the Interim Approach provides a reasonable, well-considered, and achievable roadmap for 2021 that balances the need to protect public health, safety, and welfare by mitigating PSPS outages with other important considerations – including cost reasonableness and environmental impacts. However, the CCAs do believe that the Interim Approach can be substantially improved through the adoption of the modifications and clarifications set forth below.

First, Section 1.1 of the Interim Approach requires that a utility providing temporary generation justify the scope and scale of the need for temporary generation based on the following considerations:

a. Historical meteorological data;
b. Historical outage data;
c. Fire spread modeling and incorporation of consequences to customer;
d. Transmission asset condition information; and
e. Transmission operability assessment information.

The CCAs recommend that this list be expanded to explicitly require that the IOUs include the following two considerations in their justifications:

f. Expected reductions in outage frequency, scope, and duration due to operational improvements and T&D safety upgrades;
g. Reductions in the amount of load that needs to be served by backup generation due to other resource and microgrid deployments.

Including these considerations will help to avoid unnecessary or duplicative backup generation deployment and associated impacts.

Second, the Interim Approach should be amended to clarify that all permanent generation deployed in a CCA's service area must be developed in coordination with, and with the consent and full involvement of, the relevant CCA program. In D.20-06-017, the Commission required that PG&E "collaborate with the CCAs in its service territory for planning and procurement processes for Make-Ready [substation-level microgrid generation] resources that may be deployed in the CCA's service territory."[6] This requirement must apply to both the Interim Approach's Pilot Project requirement and the 2022-forward Application requirement. This would ensure that IOU temporary generation plans are consistent with, and not duplicative of, CCA projects and procurement. A number of CCAs are working on, or have interest in, projects that may reduce or eliminate the need for IOU-supplied temporary generation, including distribution-connected microgrids in high-outage-risk areas and targeted deployment of preferred resources in high-risk areas. In addition, some CCAs may have an interest in using existing or new CCA-procured generation resources (either temporary or permanent) to partially or fully supply IOU-islanded substations during PSPS events.

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6 D.20-06-017 at 80.

Interim Approach Question 2:

> *Does a utility transmission de-energization event, such as a PSPS or other outage, present an immediate temporary need for the utility to operate generation to help alleviate a threat to public health and safety?*

Response to Interim Approach Question 2:

The CCAs strongly believe that transmission de-energization events, including PSPS outages, present an immediate threat to the public health, safety, and welfare. The IOUs have a duty to avoid these outages to the greatest extent possible, and, to the extent that outages are absolutely necessary, to mitigate the impacts of the outages as much as possible. Operating temporary generation is one part of this greater duty.

Interim Approach Question 4:

> *As a first step toward transitioning away from diesel generation, is it reasonable to require a utility seeking to deploy temporary generation in 2021 to pilot clean substation microgrid projects that would be operational for the 2021 or 2022 fire seasons?*

Response to Interim Approach Question 4:

The CCAs support the pilot project requirement, with modification. Currently, staff is proposing that IOUs must only propose pilot projects if they meet the following three criteria:

1. The project is technically feasible;
2. The project is safe;
3. The IOU considers the project financially competitive.

The CCAs recommend that these criteria be modified. Only pilot projects that meet the following criteria should be permitted:

1. The project is technically feasible;
2. The project is safe;

3. If located in a CCAs' service area, the project has full consent and participation of the CCA;
4. The project is intended to serve substations that are anticipated to have long-term backup-generation need (lasting for the expected pay-off period of the generation asset) that will not be significantly reduced or eliminated by current or planned T&D system upgrades or operational improvements within the generation resource's expected capital cost recovery period.

As discussed above, costs for clean generation microgrids may be higher than fossil-fueled technologies for a variety of reasons, hence the IOUs should not be allowed to dismiss clean substation microgrid pilot development based solely on the IOUs subjective opinions regarding cost reasonableness.

Finally, the CCAs recommend that IOUs be *required* to propose at least one pilot project if they can identify one or more potential projects that meet these criteria.

<u>Interim Approach Question 5</u>:

> *Please indicate support or opposition to the first condition for pilot projects (Attachment B, Paragraph 2.1). Is it reasonable to require a utility to install stationary generation, considering that there is a risk of stranded costs and a more comprehensive framework for transitioning from diesel has not yet been established?*

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

In light of IOU commitments to improve T&D safety and reliability, there is a substantial risk that permanent backup generation resources installed to mitigate transmission-level outages will end up as stranded assets. Based on information provided by the IOUs to date, it is reasonable to expect that most of the transmission-level outage risks could be eliminated in the next five years as the IOUs identify and implement the easiest "low hanging fruit" safety improvements. This is far shorter than the IOUs' normal capital cost recovery period for generation investments, creating a substantial risk that ratepayers will be on the hook for generation resources that do not provide any meaningful resiliency benefit.

For permant gas backup generation, this problem is exacerbated by the State's policies in favor of GHG reductions, increased renewable generation, and transitioning away from fossil generation. There is a high likelihood that any permanent gas backup generators will become stranded assets as the State pursues these goals. As such, the Commission must prohibit the use of fossil generators for permanent backup generation.

For renewable generation, the placement and size of such resources will be determined by the need to directly connect to the substation(s) in question rather than the normal suite of considerations used to determine optimal renewable siting. This means that permanent generation installed primarily for the purpose of providing backup power may be less efficient and competitive than other generation projects, potentially resulting in partially stranded assets.

As such, the Commission must compare the expected duration of the transmission outage risk in light of current or planned T&D upgrades against the expected cost recovery period for the generation resource to determine whether permanent generation is appropriate.

III. RESPONSES TO QUESTIONS ON TRANSITIONING TO CLEAN TEMPORARY GENERTION IN 2022 AND BEYOND

Future Transition Question 1:

> *Do you support the proposal for a process for transitioning to clean temporary generation in 2022 and beyond? Please respond with a "yes" or a "no" and discuss your reasoning. If you do not support this proposal, provide an alternative proposal for a long-term approach.*

Future Transition Question 1:

The CCAs support the 2022 Proposal with one clarification. The Proposal requires that the IOUs file an Application that addresses the replacement of diesel temporary generation from 2022-forward, including any plans to develop permanent generation resources to replace the need for temporary generation resources in the next 5-10 years.[7] While the CCAs support this requirement, it would be significantly strengthened by the addition of language clarifying that *all* IOU-procured permanent generation intended to supply substation-level microgrids must be considered through this Application process. In Track 1 of this Rulemaking, PG&E informed the Commission that, as part of its DEGEMS proposal, it intended to procure permanent generation resources to supply substation-level Microgrids through an advice letter ("AL") process under the Integrated Resources Plan ("IRP") proceeding.[8] Problems with this approach were identified by a number of parties in Track 1 comments. The 2022 Proposal's Application process is a much better approach, as it requires a holistic consideration of temporary and permanent generation solutions that would help to prevent duplicative outcomes. The Commission must ensure that *all* permanent and temporary backup generation proposals are considered through this Application process. In addition, as set forth above, all permanent and temporary generation proposals that would be connected to substations in CCA service areas, or would serve CCA customers, must be developed with the full consent and involvement of the CCA.

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7 Interim Approach at 6.

8 PG&E Track 1 Opening Testimony at 1-10.

IV. CONCLUSION

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

Dated: September 25, 2020

Respectfully submitted,

/s/David Peffer

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On Behalf Of:
Marin Clean Energy
Peninsula Clean Energy Authority
Central Coast Community Energy
Redwood Coast Energy Authority
Pioneer Community Energy
Sonoma Clean Power Authority
East Bay Community Energy

ADVANCING LOCAL ENERGY CHOICE

September 29, 2020

CPUC Energy Division
Attn: Tariff Unit and Edward Randolph, Director
505 Van Ness Avenue
San Francisco, CA 94102

By email: EDTariffUnit@cpuc.ca.gov

Re: CalCCA Protest to PG&E AMP Advice Letter in response to Decision 20-06-003

Dear Tariff Unit and Mr. Randolph:

Pursuant to General Order 96-B, the California Community Choice Association (CalCCA)[1] submits this protest to Pacific Gas & Electric Company's Advice Letter 4308-G/5943-E ("Advice Letter").

Pacific Gas & Electric Company (PG&E) filed its Advice Letter on September 9, 2020 in response to Decision ("D") 20-06-003, Ordering Paragraph ("OP") 83 and OP 87.

> OP 83: To implement the arrearage management payment (AMP) plan, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company must each file a Tier 2 Advice Letter within 90 days of this decision to implement the AMP plan.
>
> OP 87: The issue of concern raised by CalCCA as it relates to the allocation of proportional recovery shall be discussed in the AMP working group and a proposed resolution shall be set forth in the Tier 2 Advice Letters that Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company file.

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

While the Advice Letter adequately addresses some requirements established in D. 20-06-003, other provisions do not adequately implement certain requirements or require further clarification.

1. By proposing that the issue of third party cost recovery be addressed in the next phase of R.18-07-005, PG&E fails to fully comply with OP 87.

CalCCA, along with the investor-owned utilities ("IOUs"), The Utility Reform Network ("TURN"), and other parties, participated in a series of AMP Working Group ("AMP WG") meetings where parties discussed and agreed to various implementation and cost recovery issues included in PG&E's Advice Letter, one of which was socialization of all AMP debt forgiveness (both IOU and CCA) costs as the preferred method for cost recovery. As expected, PG&E proposes to socialize the recovery of both bundled and unbundled customers' AMP debt forgiveness among all customers. However, in its Advice Letter PG&E further states that it believes "Commission approval is needed to proceed with third party AMP cost recovery."[2]

OP 87 clearly states that a resolution to the issue of cost recovery was to be set forth in the Advice Letters. By proposing to add the topic of cost recovery to "the rate setting phase of the proceeding,"[3] PG&E fails to comply with OP 87 and creates an additional obstacle to achieving the Commission's intent of offering customers, both unbundled and bundled, access to an AMP program that does not burden certain ratepayers more than others through disproportionate cost recovery. At the prehearing conference (PHC) for the Percentage of Income Payment Plan (PIPP) phase of the proceeding held on September 17, 2020 PG&E suggested that the Commission is unable to approve the proposed cost recovery mechanism through an Advice Letter because proper notice has not been provided to affected parties.[4] This proceeding, however, focused centrally on vulnerable customers, including CARE and FERA customers, making clear that program funding could be affected. Moreover, D.20-06-003 further made clear that the details of cost recovery would be addressed by the AMP WG. Finally, this Advice Letter provides yet another opportunity for comment. By approving the proposed cost recovery without change, the Commission will, indeed, make clear that it has approved this methodology without question, as PG&E requires.

Of further concern to CalCCA is the proposal that "third-party service providers that elect to participate in the AMP prior to Commission authorization of the socialized cost recovery approach would be responsible for tracking and recovering unbundled customers' AMP debt forgiveness associated with the third party provider's charges."[5] This is troublesome for three

[2] PG&E Advice Letter at p. 13.
[3] PG&E Advice Letter at p. 13.
[4] PHC Transcript at p. 34.
[5] PG&E Advice Letter at p. 14.

reasons. First, this implies that all forgiven debt would be recovered solely from the ratepayers that each individual CCA serves and that debt forgiven prior to Commission approval of socialized recovery, under PG&E's proposal, would not be eligible for socialized cost recovery once it is approved by the Commission. This would disproportionately burden CCA communities with higher AMP participation than others. Second, CCAs have no certainty about a timeline for when the issue of cost recovery could be resolved. Indeed, PG&E proposed in the recent PHC addressing the PIPP that AMP cost recovery be addressed in the PIPP working group, and the Administrative Law Judge indicated that he anticipates an 18 month resolution to the PIPP phase.[6] Third, taking PG&E's approach would leave CCAs with no certainty of the ultimate outcome, which would discourage CCA participation in the AMP program.

Furthermore, PG&E is requesting that CCAs in its territory notify it "within 45 days of this AL regarding their intent to participate."[7] CCAs are being asked to make a determination about participation in the AMP without knowing if their participation risks ultimately burdening their ratepayers with disproportionate cost recovery. CCAs have and continue to be supportive of the AMP and would like to be able to offer their unbundled customers access to the program, especially since many customers face economic hardship due to the COVID-19 pandemic. However, PG&E's proposal makes CCA participation in the program difficult because neither the magnitude of the potential financial impact of participating in the program before socialized cost recovery is approved nor the timeline for third-party cost recovery to be authorized are known. CalCCA requests that PG&E clarify whether the requested 45 day notification is 45 days after the disposition of the Advice Letter or 45 days after the date it was filed. If PG&E requests notification 45 days after the date the Advice Letter was filed, CalCCA requests that the Commission provide guidance on cost-recovery through approval of the AMP Advice Letters prior to the 45 day mark.

2. **PG&E did not adequately address what information it will provide CCAs that notify PG&E they intend to participate the AMP.**

With respect to coordination with third-party providers, PG&E states that it is "coordinating with the CCAs to determine the customer information that PG&E must share with the CCAs to enroll customers in the program as well as the appropriate channels to provide that information in a secure and efficient manner."[8] CalCCA is unaware of any coordination or outreach to CCAs besides the coordination that occurred as part of the AMP WG. Given that the AMP WG spent substantial time discussing the data that would need to be communicated to CCAs to enable third-party participation and that CalCCA provided tables specifying the requested information, CalCCA is surprised that PG&E failed to include any mention of the specific data that would be shared with CCAs. Under the situation proposed by PG&E, where CCAs would be responsible for tracking and recovering all forgiven debt prior to a Commission

[6] PHC Transcript at p. 20.
[7] PG&E Advice Letter at p. 14.
[8] PG&E Advice Letter at p. 13.

approval of socialized cost recovery, the data that is communicated to the CCAs is of central importance. For example, CCAs have no visibility into the amounts owed to the IOU. Because eligibility is determined based on both IOU and third-party arrears, a CCA would have no way of knowing with certainty which of its customers are eligible for the AMP or which have enrolled. Additionally, the dollar value of arrears that are expected to be forgiven, the value of forgiven amounts that have been processed, and whether a customers has made the monthly payment it was supposed to make and is still in good standing in the program must be communicated to the CCAs that participate in the program.

CalCCA agrees with PG&E that "existing channels to share required information" should be leveraged. However, what specifically that information is should be added to the Advice Letter or PG&E should set up regular meetings related to AMP data needs with CCAs to ensure program alignment and streamlined customer enrollment. Finally, PG&E uses the word "required" to describe the information that it intends to share with CCAs. CalCCA requests that PG&E clarify what it means and whether it is stating that only information required by the Commission to be shared to CCAs would be shared.

We thank the Commission for its consideration of this protest and urge the Commission to require PG&E to re-file its Advice Letter so that it includes the information it plans to share with CCAs that intend to participate in the AMP and a proposal for how it intends to track and recover all forgiven bad debt, including third-party charges.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

cc: PGETariffs@pge.com
Service List R. 18-07-005

OCTOBER FILINGS

Submit comment on September 15 and 17 Working Group

Initiative: Resource adequacy enhancements

1. Provide a summary of your organization's comments on the September 15 and 17, 2020 working group discussion:

CalCCA continues to support CAISO's RA Enhancements in general, but opposes certain elements:

- Hybrid resource UCAP should not be adjusted based on the availability of the VER component, including due to use of the dynamic limit tool to reflect availability due to fuel limitations.
- CAISO's proposal to continue the current planned outage process with a replacement requirement will lead to greater amounts of replacement capacity than would be required if CAISO were to implement a planned outage replacement margin and has significant problems for local capacity resources that have limited replacement resources available.
- CAISO should not implement a source-to-sink firm transmission requirement for Import RA resources and should address potential market power issues before implementing a last leg firm transmission requirement.
- CalCCA believes CAISO's approach for applying UCAP for local capacity resources after identifying the LCR need based on NQC could work, but questions whether doing so actually adds any value given that the current pool of available local resources is limited and is already constrained both by resources' effectiveness factors and their forced outage rates. CalCCA also notes that CAISO's maintenance outage replacement requirement will create problems for local capacity resources, and also urges CAISO to coordinate with the Central Procurement Entities to ensure that the UCAP requirement does not result in an increase in local capacity procurement requirements without balancing costs and benefits.

2. Provide your organization's feedback on the Unforced Capacity Evaluations topic as described in slides 6-68:

Co-Located UCAP

CalCCA supports CAISO's proposal to apply the UCAP methodology to co-located resource storage components, while using the ELCC for the solar component. We note that as the CAISO transitions to assessing resource adequacy on a more granular level via the portfolio assessment, it may make sense in the future to revisit the use of ELCC for Variable Energy Resources (in coordination with the CPUC as the LRA), since the impacts of their variability and their contributions toward meeting resource adequacy may be better captured directly by the portfolio assessment. CAISO already appears to be moving in this direction by proposing to model VERs in the portfolio assessment using their expected output profile.

Hybrid UCAP

CalCCA supports CAISO's proposal in the Hybrid resource Initiative to use outage cards for hybrid resource mechanical outages, while using the dynamic limit tool to communicate ambient derates or absence of the variable component due to fuel limitations. CalCCA is concerned, however, that the

CAISO's proposal to determine the Hourly Unavailability Factor for hybrid resources results in a double- or potentially triple- penalty, despite CAISO's statement on Slide 54 that it will not double count outages. For both standalone variable renewable resources and the renewable component of co-located resources, ELCC values alone are used to set UCAP values. This is due to the fact that the ELCC methodology takes into account the probability of forced outages for wind and solar resources. Therefore, reductions to hybrid resource counting due to application of forced outages in the Hourly Unavailability Factor calculation will be on top of adjustments that already have been reflected in the hybrid resource's ELCC. In addition, on Slide 54, CAISO recognizes that there will need to be coordination with the LRA to avoid double counting between the Hourly Unavailability Factor and the QC methodology. But, under the current CPUC QC methodology for hybrid resources with ITC charging limitations, the reliability value of the variable renewable component is discounted by the energy required to charge the storage component before applying the ELCC to the remaining renewable capacity. Thus, the hybrid resource QC has been adjusted downward by the amount of charging energy needed from the VER component.

The dynamic limit tool proposed by CAISO in the hybrid resources initiative is intended to ensure feasible dispatch schedules despite deviations between forecasted and actual renewable availability. In the Hybrid Resources Draft Final Proposal, CAISO explains that "forecast values from variable energy resource components…will likely be drivers to how much energy the resource can deliver to the market."[1] CAISO's proposal to use the dynamic limit impacts to determine the Hourly Unavailability Factor for hybrid resources in the RA Enhancements initiative would therefore result in an additional penalty, as the renewable component of hybrid resources would be subject to both ELCC, which accounts for intermittency of VERs, as well as application of the dynamic limit tool to account for fuel availability. As discussed above, the CPUC's QC methodology would further reduce UCAP hybrid resources. The reliability value of variable renewable resources in a hybrid configuration would therefore be undercounted relative to co-located and standalone renewables despite no difference in the underlying factors driving their availability. CalCCA therefore recommends that adjustments to hybrid resources UCAP values reflect only forced outages to the storage component and not include dynamic limit adjustments related to the VER component.

3. Provide your organization's feedback on the RA Imports topic as described in slides 71-120:

While CalCCA continues to support the proposed resource specific (including aggregations) import RA requirements, we continue to oppose a source-to-sink firm transmission requirement for import RA. As an initial matter, while CAISO states on Slide 84 that there is precedent for firm transmission requirements for RA imports in other ISOs and RTOs, CAISO ignores the direct existing precedent that no such requirement currently exists for CAISO's import RA. Creating such a requirement without first addressing the potential market power issues that would be created by the requirement would harm California consumers. The way that market power is addressed in the Open Access Transmission Tariff (OATT) is by requiring unused long-term transmission rights be released prior to real-time. If CAISO requires import RA to demonstrate firm transmission prior to real-time, CAISO will have voluntarily created a requirement that thwarts this critical market power mitigation tool. To blithely suggest that CAISO market participants should raise concerns about market power that does not yet exist under a transmission provider's OATT shirks CAISO's responsibility to take a reasoned approach in evaluating the potential impacts of changes to its Tariff; those impacts include the potential seams issues and rules misalignment, including the possibility that the neighboring OATT

[1] Hybrid Resources Draft Final Proposal, pg 10.

transmission release rules would no longer protect CAISO market participants against the exercise of market power.

BPA's own data illustrates the paucity of long-term transmission that has been released by the parties holding expiring long-term firm transmission rights.[2] Table 1.1 and Table 1.2 extracted from BPA's Southern Intertie Data report provide a clear indication that parties that do not currently hold long-term rights on BPA's Southern Intertie are not likely to be able to obtain expiring long-term firm transmission rights. Between 2012 and 2018, in five of the seven years none of the megawatts up for renewal were released. In the two years that megawatts were released, only 20 MW and 148 MW, 4% and 31% were released. Put another way, Table 1.2 shows that typically 100% of Transmission Service Requests (TSRs) were renewed and in one case the TSR that was not renewed was replaced by a new original request from the same party that had the expiring TSR. While some long-term firm transmission rights are not subject to renewal priority, these amounts are small in comparison to the potential Import RA amounts needed. What the BPA data suggests is that parties that do not currently hold BPA Southern Intertie long-term transmission rights are extremely unlikely to be able to obtain those rights from BPA at BPA's cost-based tariff rates to support their RA imports. Instead, they will have to obtain the rights from the current holders, who have priority renewal rights and who are not required to release any unsold rights until just prior to real-time.

Table 1.1: Number of MWs Renewed per Year

Fiscal Year	MWs up for Renewal	Renewed/Original Service	% MWs Released
2012	357	357	0%
2013	1431	1431	0%
2014	624	624	0%
2015	506	348	31%
2016	683	683	0%
2017	487	467	4%
2018	2683	2683	0%

Table 1.1 above shows the Transmission Service Requests (TSRs) MWs up for renewal, the MWs renewed, and the percent of MWs not renewed.

[2] Southern Intertie Data as of FY 2018, Bonneville Power Administration, January 28, 2019.

Table 1.2: Count of TSRs Renewed per Year

Fiscal Year	Count of TSRs w/ Renewal Decision	Count of TSRs Fully Renewed	% TSRs Fully Renewed
2012	1	1	100%
2013	9	9	100%
2014	7	7	100%
2015	12	7	58%
2016	13	13	100%
2017	3	2	67%
2018	17	16	94%

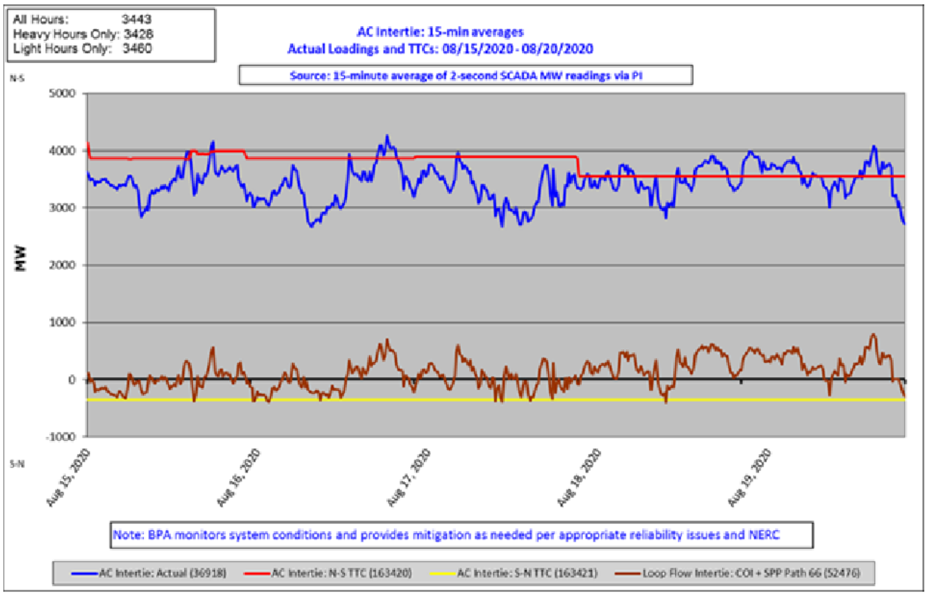
Table 1.2 above shows the number of Transmission Service Requests (TSRs) with a renewal decision by fiscal year, the number that were fully renewed, and the percent that were fully renewed.

In fiscal year 2018, no customer with the option to renew service reduced the amount of their long term Southern Intertie transmission reservations. One customer did not renew a TSR but had a new original request beginning in the month the non-renewed TSR ended.

The good news is that the data CAISO included in Slides 116 and 117 demonstrate that even during extremely stressed system conditions from August 15, 2020 through August 20, 2020, the amount of power flow on the California-Oregon Interface and the Nevada-Oregon Border intertie were near (or even slightly above) the respective Total Transfer Capability of those interties. This was the case even without the more stringent firm transmission requirements that CAISO is considering implementing. In contrast, the flowgate data CAISO included on Slides 98 – 100 show that those flowgates were not binding during stressed conditions. If CAISO is concerned about the deliverability of import RA resources, CAISO could put limits on the amount of RA import resources shown that are located on the constrained side of the most critical flowgates.

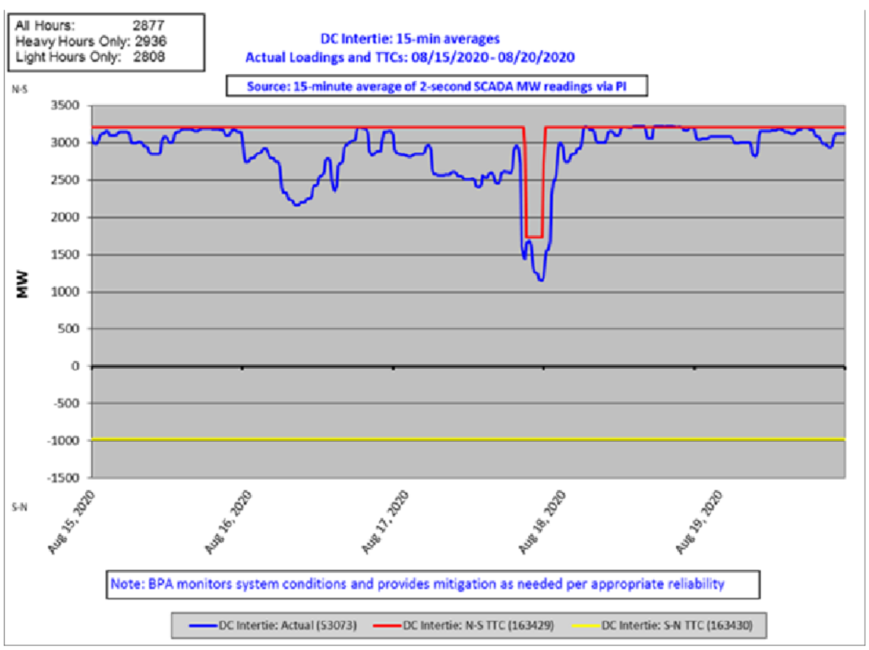
Further, it is important for CAISO to recognize that the COB and NOB interties are managed paths; the total transfer capability on the California side of the interties aligns with the TTC on the BPA Southern Intertie. Whatever transmission is available within California is matched by transmission on the BPA system. This is true whether or not California parties have contracted with BPA for long-term transmission rights.

California-Oregon Interface (AC intertie)



Underlying 15-min interval data averaged into hourly values from BPA website, found here: https://transmission.bpa.gov/Business/Operations/Paths/

Nevada – Oregon Border (NOB or DC Intertie)



Underlying 15-min interval data averaged into hourly values from BPA website, found here: https://transmission.bpa.gov/Business/Operations/Paths/

4. Provide your organization's feedback on the Planned Outage Process Enhancements topic as described in slides 121-125:

CalCCA is disappointed that CAISO has decided not to implement the planned outage reserve margin and to instead maintain the existing planned outage replacement requirements with minor enhancements. First, we believe the statement on Slide 122 that the planned outage reserve margin was generally opposed by the stakeholder community mischaracterizes the comments submitted on CAISO's 5th Revised Straw Proposal. The majority of commenters did not comment on this aspect of the 5th Revised Straw Proposal (18 out of a total on 30 parties). Of those that did, seven entities either supported or conditionally supported the planned outage reserve margin (CalCCA, Calpine, Middle River Power, NRG support; NCPA, National Hydropower Association and Yuba County Water Agency would support if planned outages were not prohibited in October), while five opposed it (DMM, Public Advocates Office, PG&E, SDG&E, Six Cities). CalCCA represents 22 operational LSEs that serve more CAISO load than the bundled load of PG&E and SDG&E combined. Allowance for hydroelectric resource maintenance outages in Summer months will need to be addressed with either the planned outage reserve margin approach or if the current process is maintained. That is, either approach will need to recognize the limited window available for hydroelectric resource operators to perform their required maintenance due to water availability and weather conditions. CalCCA acknowledges that the planned outage reserve margin approach provides slightly less incentive for parties to minimize the duration of their planned outages, but we believe that the potential lost revenues and the costs associated with performing maintenance outages already provide sufficient incentive for resources owners to minimize the duration of their maintenance outages.

By continuing the current maintenance outage process, CAISO will miss an opportunity to reduce the aggregate amount of replacement capacity that will be required to cover the maintenance outages. Under CAISO's latest proposal to prohibit RA resource maintenance outages absent a replacement resource being provided, resource operators likely will need to acquire replacement capacity for an entire month, even if their maintenance outage is expected to last a single week. Worse, if the maintenance outage were to span two calendar months (even if it lasts only a single week), replacement capacity would need to be procured for two months. The planned outage reserve margin approach would allow for less replacement capacity in aggregate, and would reduce the amount of potential RA capacity that resource owners may hold in reserve to self-supply the increased amount of replacement capacity. Further, it will be extremely difficult, if not impossible, for owners of local capacity resources to obtain replacement capacity so that their maintenance outages will be approved. In many local capacity areas, all of the local resources are needed to satisfy local area or sub-area requirements. Absent a well-defined waiver process, the proposed prohibition on maintenance outages without replacement capacity will make it impossible for these resources to receive authorization for required maintenance. Reliance on opportunity outages will make it difficult for resources to plan for outages and is likely to increase costs. Treating the outages as forced outages will lower the UCAP for the local area without changing the required NQC or the pool of resources that can meet the requirement. For other local capacity areas, with limited resources that can provide replacement capacity for that specific local area or subarea, it seems likely that a resource owner seeking replacement capacity for maintenance outages would be exposed to the exercise of market power without any means for the market power to be mitigated. These issues will need to be addressed for the CAISO's proposed approach to become workable. For the above reasons, CalCCA urges the CAISO to reconsider its decision to reject the planned outage reserve margin approach.

5. Provide your organization's feedback on the UCAP for local topic as described in slides 126-139:

CalCCA believes CAISO's approach for applying UCAP for local capacity resources after identifying the LCR need based on NQC could work, but questions whether doing so actually adds any value given that the current pool of available local resources is limited and is already constrained both by resources' effectiveness factors and their forced outage rates. As new resources are added, incorporating forced outage rates into the local RA evaluation will incentivize increased reliability, but we are concerned that overlaying the UCAP requirement on local capacity resources may unnecessarily complicate the local capacity procurement process. Further, as noted in our comments above about the challenges presented by CAISO's proposal to require replacement capacity for all maintenance outages, CAISO will need to address this issue explicitly for local capacity resources if it doesn't adopt a planned outage reserve margin approach. Finally, CAISO should coordinate with the Central Procurement Entities to ensure that the UCAP requirement does not result in an increase in local capacity procurement requirements without balancing costs and benefits.

6. Additional comments on the September 15 and 17, 2020 working groups:

October 8, 2020

CA Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Reply to Protests of MCE Advice Letter 45-E

Re: Protests of the Public Advocates Office and the Small Business Utilities Advocates to Marin Clean Energy's Advice Letter 45-E (Energy Efficiency Annual Budget Advice Letter for Program Year 2021)

Dear Energy Division Tariff Unit:

Marin Clean Energy ("MCE") hereby replies to the protests dated October 1, 2020 from the Public Advocates Office ("PAO") and the Small Business Utilities Advocates ("SBUA") to MCE's Advice Letter 45-E, Marin Clean Energy's 2021 Energy Efficiency Annual Budget Advice Letter ("2021 ABAL"), filed September 1, 2020.

I. PAO's Protest

PAO protests the 2021 ABALs of all of the energy efficiency ("EE") program administrators ("PAs"). In doing so, PAO makes several claims relevant to MCE. PAO claims that MCE's 2021 total resource cost ("TRC") forecast should be discounted based on prior performance, that MCE should be required to file a supplemental ABAL to substantiate its forecasted cost effectiveness, and that all PAs should be required to reallocate funds to residential programs, though PAO offers no specific adjustment for MCE. MCE addresses each of PAO's claims in turn.

A. MCE Has Substantiated its 2021 Forecast.

PAO claims that MCE's forecasted TRC score, the measure of cost effectiveness in California, is overly optimistic based on MCE's past performance.[1] On this basis alone, and without proper consideration of MCE's new and expanded programming described in its 2021 ABAL, PAO asks that the Commission heavily discount MCE's 2021 TRC forecast.[2] For the following reasons, PAO's protest should be denied.

As an initial matter, the primary reason that MCE has fallen short in past years on its claimed cost-effectiveness compared to its forecasted cost-effectiveness is that MCE has been in the process of

[1] The Public Advocate Office's Protest of Energy Efficiency Annual Budget Advice Letters for Program Year 2021 at pp. 4-5 ("PAO Protest").

[2] PAO Protest at p. 5.

significantly ramping up its program portfolio both in existing and new sectors. The Commission has already addressed the necessity of such a ramp-up period and acknowledged that leniency as to cost effectiveness requirements would be required during such ramping. In Decision 18-05-041, the Commission required a portfolio forecast TRC of 1.0 during the ramp years (program years 2018-2022) and acknowledged that it would be challenging for transitioning programs to achieve a 1.0 TRC on an evaluated basis.[3] For these reasons, the Commission set out a specific process for addressing such concerns.[4] In addition, in the past Energy Division has declined to reject ABALs on the basis of concerns such as those PAO asserts.[5]

Contrary to PAO's protest, the Commission has expressly stated that during these ramp years, the goal is to transition gradually to full cost-effectiveness without prematurely "obligating the PAs to cut programs with low TRCs."[6] The Commission established a 2018-2022 ramp period as a "provision for continuity" and in recognition of the gradual nature of the transition period.[7] Prematurely changing course mid-transition would cause uncertainty that is harmful to the EE market and to programs under development. The Commission has already made provision to avoid such uncertainty and to give new PAs the opportunity to ramp up.[8] Thus, *even if* the Commission were to find that MCE's forecasted TRCs were in question, such a finding should still not prevent approval of MCE's 2021 ABAL or its forecasted TRCs. As Energy Division clearly stated in response to a similar protest from PAO last year, "having doubts about a program's or portfolio's ability to achieve forecast savings or cost effectiveness is not grounds for rejecting an ABAL per Decision D.18-05-041."[9]

Moreover, MCE's programs are accurately forecasted to become increasingly cost effective in the coming years, including 2021. Below, MCE directly addresses cost-effectiveness concerns, reiterates program developments that will impact cost effectiveness in 2021, and substantiates its 2021 forecast. However, the Commission should also note that PAO's protest ignores and does not address many of MCE's stated going-forward strategies, including specifically identified strategies that MCE is employing to increase cost effectiveness in 2021.[10] MCE's 2021 ABAL explicitly addresses cost-effectiveness concerns such as COVID-19 impacts, asymmetry in the implementation of the TRC test that should be remedied, the timing and uncertainty of avoided cost calculator updates, and other subjects.[11] It also sets forth multiple strategies to increase cost

[3] Decision ("D.") 18-05-041, *Decision Addressing Energy Efficiency Business Plans*, at p. 135 (June 5, 2018).

[4] D. 18-05-041 at p. 137.

[5] *See, e.g.*, Energy Division Letter approving MCE's 2020 ABAL, Advice Letter 37-E, at pp. 3-4 (Dec. 20, 2019).

[6] D. 18-05-041 at p. 137.

[7] D. 18-05-041 at p. 137.

[8] *See* D. 18-05-041 at p. 137.

[9] Energy Division Letter approving MCE's 2020 ABAL, Advice Letter 37-E, at p. 5.

[10] 2021 ABAL at p. 10.

[11] 2021 ABAL at pp. 8-11.

effectiveness in 2021, including new program roll-outs and ramp-ups, the adoption of advanced implementation strategies, and the use of AMI analytics for targeting and optimizing program delivery, aligning incentives, and driving accountability.[12] This information was not accounted for in PAO's protest.

Further, MCE's 2021 ABAL describes recent and proposed portfolio and program changes, including that the 2021 period will be the first year since it filed its Business Plan that MCE will launch no new EE programs.[13] Launching a new program requires a significant upfront investment that typically lowers a program's TRC. Instead, MCE will close one program that is not cost effective.[14] MCE will also continue to ramp up and expand other programs that are expected to be cost effective in part because of an increased focus on implementation strategies such as population-level Normalized Metered Energy Consumption ("NMEC"). MCE provides compensation for NMEC-based programs based only on performance as documented by actual metered savings, not deemed savings.[15] This approach ensures that dollars are only spent when savings are achieved. MCE's population-level NMEC initiative will incentivize time-dependent savings, thoughtful measure selection, and customer targeting focused on load shape and demand profiles, which results in higher cost effectiveness.

MCE's increased deployment of Strategic Energy Management ("SEM") and Behavioral, Retrocommissioning, and Operational ("BROs") participating pathways will also contribute to enhanced performance. MCE designed these participation pathways to help large industrial, agricultural, and commercial customers overcome the barriers associated with cost-effective EE investments. MCE is scheduled to report the annual savings of two cohorts under these approaches in 2021 for the first time.

PAO's contention that MCE's forecast for 2021 is not credible rests on the false assumption that past performance dictates future performance. In the context of MCE's still-developing EE portfolio, that assumption is misplaced. As noted in MCE's 2021 ABAL, MCE has launched and ramped up five new programs since the Commission approved its Business Plan, including three programs in 2019 and two programs in 2020.[16] These programs required initial investments that will begin to pay dividends in the near future. Indeed, MCE expects to generate savings from these programs in 2020 and 2021. As explained in MCE's 2021 ABAL, its residential Single-Family Comprehensive Program, as well as its non-residential programs, are currently ramping up and are

[12] *See* 2021 ABAL at pp. 10-11.

[13] *See* 2021 ABAL at p. 12.

[14] 2021 ABAL at p. 12.

[15] 2021 ABAL at pp. 12-13.

[16] *See* 2021 ABAL at p. 10.

expected to deliver cost-effective savings soon.[17] These savings will help offset other less cost-effective programs that deliver value to meet other CPUC policy goals.

MCE has substantiated the basis for its 2021 cost-effectiveness forecast. However, as noted above, and detailed below, even if MCE does fall short of its forecasts, the Commission has already established a process to address low TRCs for programs ramping up. For this reason, MCE respectfully requests the Commission to reject PAO's request to discount MCE's 2021 EE forecast based on reporting in prior years.

B. PAO's Request for Supplemental ABALs Should Be Rejected.

PAO suggests that the Commission reject the 2021 EE portfolios of San Diego Gas & Electric, Southern California Gas, and MCE and "require these PAs to file supplemental ABALs justifying their forecasts and modifying their portfolio to better support long-term cost effectiveness."[18] As noted above however, "having doubts about a program's or portfolio's ability to achieve forecast savings or cost effectiveness is not grounds for rejecting an ABAL per Decision D.18-05-041."[19]

Further, MCE fully substantiated its forecast in its 2021 ABAL, as detailed above.[20] MCE also indicated in its 2021 ABAL that it has or will eliminate multiple programs that are not cost effective.[21] As a consequence, PAO's request that MCE submit an additional filing to substantiate its forecast and modify its portfolio is not necessary and should be rejected.[22]

MCE has already documented the strategies and steps it is taking to improve it's portfolio cost-effectiveness, including the upcoming elimination of a non-cost-effective program (the Multifamily Direct Install Program) at the end of the year, the expansion of the Commercial Upgrade Program including further reliance on NMEC, the use of new AMI analytics to understand COVID-19 impacts and focus interventions with greatest potential return, the

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[17] 2021 ABAL at p. 10.

[18] PAO Protest at p. 6.

[19] Energy Division Letter approving MCE's 2020 ABAL, Advice Letter 37-E, at p. 5.

[20] *See* 2021 ABAL at pp. 6-13.

[21] 2021 ABAL at 12.

[22] In addition, the ABAL normally is not the proper place for major course shifts. *See* D. 15-10-028, *Decision Re Energy Efficiency Goals for 2016 and Beyond and Energy Efficiency Rolling Portfolio Mechanics*, at p. 62 (Oct. 28, 2015) ("The question for Staff in reviewing a budget advice letter should be 'does this conform to the approved business plans?'"). A PA's portfolio is properly reviewed in its Business Plan.

deployment of SEM and BROs, and other steps.[23] In addition, MCE has explained that it is in the process of ramping up its more cost effective programs.[24]

MCE has also met the ABAL review criteria required during the transition period from 2018-2022. During that period, the Commission requires a TRC of at least 1.0 as well as a number of other required ABAL components enumerated in Sections 7.2 and 7.3 of D. 18-05-041.[25] For a PA with forecasted portfolio TRCs between 1.00 and 1.25 during the transition period, the Commission requires an additional process to ensure the PA's portfolio is cost effective on an evaluated basis.[26] This additional process requires that the PA host a workshop process to 1) explain why its forecasted TC does not meet or exceed 1.25; 2) describe how it intends to achieve a portfolio TRC forecast of at least 1.25 by program year 2023; and 3) describe how the PA intends to achieve a portfolio that meets or exceeds 1.0 on an evaluated basis during the transition period.[27]

Based on the transition period process detailed in D. 18-05-041, the workshop process set forth by the Commission in that order is the appropriate venue for PAO to gather any additional information on MCE's 2021 portfolio cost-effectiveness forecast.[28]

Because processes are already in place to allow PAO to gather additional information, the Commission should reject PAO's request for a supplemental ABAL filing and PAO's suggestion that further changes may be needed to MCE's portfolio at this time.

C. PAO's General Recommendation that the PAs Reallocate Funds to Residential Programs is a Policy Question Not Appropriate for an ABAL Protest and Would Be Counter-Productive As Applied to MCE.

Finally, PAO makes a general recommendation that the PAs be required to reallocate funds away from agricultural, commercial, industrial, and public sector EE programs in order to redirect funds to residential EE programs.[29] PAO suggests specific re-allocations for PG&E, SCE, SDG&E and SoCal Gas, but fails to make any specific recommendations with regard to MCE's budget. To the

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[23] 2021 ABAL at pp. 10-13.

[24] *See* 2021 ABAL at p. 10.

[25] See D. 18-05-041 at pp. 123-137.

[26] D. 18-05-041 at pp. 134-137.

[27] D. 18-05-041 at p. 135.

[28] *See* D. 18-05-041 at pp. 134-137.

[29] PAO Protest at p. 7.

extent PAO intends that this recommendation apply to MCE, the Commission should disregard PAO's recommendation.

First, ABALs are intended to be ministerial in nature rather than policy-focused.[30] The policy question of whether to re-focus the state's energy efficiency programs in new directions as a result of COVID-19 is not an appropriate subject for a protest to an ABAL.[31]

While MCE agrees with PAO that residential customers are facing hardships as a result of COVID-19, PAO does not substantiate its claim that residential programs will necessarily be more cost-effective. On the contrary, many residential programs are cost-intensive, requiring extensive expenditures for outreach and education. The costs of such outreach may increase during COVID-19 to ensure proper social distancing. Therefore it is unclear that granting PAO's request would further PAO's stated goal of enhancing cost-effectiveness.

In an effort to become more cost effective, MCE has recently closed certain residential programming and expects that re-opening those programs would in fact harm MCE's EE portfolio TRC. MCE's portfolio will be more cost-effective when it appropriately and fully incorporates other sectors such as agricultural, commercial, and industrial customers. Because the Commission only recently permitted MCE to provide EE programming for these larger customers,[32] it is not reasonable or rational to now require MCE to abandon the upfront investments it has made in developing new programs during the last two years.

The Commission should deny PAO's request to redirect funds to residential programming, which would be counter-productive as applied to MCE and in any event is not the proper subject of an ABAL protest.

II. SBUA's Protest

SBUA similarly protests the 2021 ABALs of all of the EE PAs. With respect to MCE, SBUA claims that MCE has not provided sufficient information to justify substantially expanding its Commercial Upgrade Program, and expresses a particular concern that larger businesses may benefit from the program more than smaller businesses.[33] SBUA also makes a generalized assertion that the Commission should require the PAs to report data and rate impacts by certain specific subgroups.[34] SBUA further states that "leeway is warranted" with respect to TRC scores

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[30] General Order 86-B at Section 7.6 (only "ministerial" matters may be delegated to Industry Division). *See also* AL 37-E at p. 3 n. 16 (citing D. 15-10-028 at p. 62 ("The question for Staff in reviewing a budget advice letter should be 'does this conform to the approved business plans?'")).

[31] *See id.*

[32] D. 18-05-041 at p. 115.

[33] Protest of Small Business Utility Advocates to the Energy Efficiency Annual Budget Advice Letters for Program Year 2021 at pp. 6-7 ("SBUA Protest").

[34] SBUA Protest at p. 7.

in light of various factors including wildfires catastrophes and COVID-19.[35] MCE addresses these assertions below.

A. MCE's Commercial Upgrade Program is Slated for a Major Ramp-Up in 2021 that Should Be Allowed to Proceed.

MCE has long been working toward a substantial ramp-up of its Commercial Upgrade Program which will come to fruition in 2021 and will substantially contribute to the cost-effectiveness of MCE's program portfolio.

Importantly, MCE is expanding its Commercial Upgrade Program to utilize the population-level NMEC platform, which will help to ensure the success of the expanded program including its cost-effectiveness. MCE's primary objective is to simplify the path for MCE to translate allocated budgets for energy efficiency into actual results in its service area. As described above, the most cost-effective means to accomplish this goal is to align EE procurement with delivered net benefits by incentivizing time-dependant savings, thoughtful measure selection, and customer targeting focused on load shape and demand profiles.

MCE's draft program design has already generated significant interest among potential partners. MCE expects at least three aggregators to support a single prime implementer under a performance-based contract. MCE plans to allocate approximately 54% of its non-administrative commercial budget to its existing commercial implementers' activities, with the remaining 46% allocated to the aggregator-driven population-level NMEC platform that MCE will launch utilizing a new implementer in the coming months. This necessitates roughly doubling the program's cost allocation, and represents the culmination of substantial foundational work, investment, and planning. However, as a pay-for-performance program, the risk to ratepayers from this expansion is limited.

As for program funds remaining at the close of 2018 and 2019, these funds were unspent as a result of the gradual nature of the ramp-up that took place in those two years. In 2018, MCE's commercial program activities were limited as MCE was working with a single implementer primarily to install deemed lighting for small commercial customers. In 2019, MCE contracted with a second implementer and then invested the remainder of the year in developing a pipeline to deliver cost-effective savings in subsequent years. In 2021, MCE's Commercial Upgrade Program will feature three implementers and four participation platforms: custom, deemed, SEM, and NMEC. This will comprise a much more well-rounded and full-fledged program than in past years.

MCE is in the final stages of contracting with an implementer and will have substantially more information available within 60 days after contract execution to facilitate additional stakeholder

[35] SBUA Protest at pp. 8-9.

input during the California Energy Efficiency Coordinating Committee ("CAEECC") stakeholder process to address PA implementation plans.

B. MCE Appreciates SBUA's Interest in Equity But Has Provided Sufficient Detail.

SBUA expresses a concern about equity as between customer types and requests that MCE provide more granular data on small, medium, and large customers that have participated in the Commercial Upgrade Program.[36] MCE appreciates SBUA's concern for equity and agrees that equity between program participants is important. MCE would be glad to follow up separately with SBUA on this question. However, an ABAL protest is not the appropriate venue to address this concern. This level of detail is not required in an ABAL, and ABALs are intended to be ministerial in nature rather than policy-focused.[37]

Pursuant to D. 18-05-041, PAs are required to report on sector-level metrics in EE Annual Report submissions. Consequently, SBUA can find details regarding participation levels by small, medium, and large customers for prior years in MCE's Annual Report spreadsheet form on the Commission's data reporting website, Energy Efficiency Statistics, known as EEStats.[38] As recorded there, in 2019, a total of 67 program participants engaged in MCE's Commercial Upgrade Program. Of those 67 total participants, 42 participants (or 63%) were small customers, 22 (or 33%) were medium customers, and 3 (or 4%) were large customers. Small commercial customers thus constituted the bulk of program participants in 2019.

MCE has provided sufficient detail regarding customer classes for the purposes of its 2021 ABAL and has provided additional detail through other established means including via EEStats. MCE would furthermore be glad to engage with SBUA on this subject privately or in other forums.

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Lastly, MCE briefly acknowledges SBUA's comment that the Commission should provide leeway to programs during the COVID-19 period.[39] MCE acknowledges that both SBUA and PAO are concerned about the impacts of COVID-19, with PAO expressing concern in its protest primarily

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[36] SBUA Protest at p. 7.

[37] General Order 86-B at Section 7.6 (only "ministerial" matters may be delegated to Industry Division). *See also* AL 37-E at p. 3 n. 16 (citing D. 15-10-028 at p. 62 ("The question for Staff in reviewing a budget advice letter should be 'does this conform to the approved business plans?'")).

[38] MCE understands that EEStats, which is normally available at www.eestats.cpuc.ca.gov, is currently offline. During the period that EEStats remains offline, SBUA may send EE data requests directly to MCE. Alternatively, an additional reference to validate EE results is available via the CEDARS "Data" tab. CEDARS, short for the California Energy Data and Reporting System, can be found at https://cedars.sound-data.com.

[39] SBUA Protest at pp. 8-9.

with respect to residential customers and SBUA expressing concerns regarding commercial customers.

MCE recognizes the importance of energy efficiency savings to all of its customers and is committed to pursuing these savings despite the challenges that programs may face in the coming year. Currently, MCE is using AMI data to analyze the impacts of COVID-19 in order to better understand changes in energy consumption, improve program performance, and develop approaches to understanding actual EE savings net of COVID-19 impacts.[40] MCE will work to reduce the risks to ratepayers and is confident that continued programming will support a healthy EE market while providing near-term benefits to a range of customer classes. MCE also recognizes that the discussion related to the pandemic's impacts on energy efficiency programs will continue in other forums including pursuant to the *Assigned Commissioner and Administrative Law Judges' Amended Scoping Ruling Addressing Impacts of COVID-19* issued in Rulemaking 13-11-005 on July 3, 2020. Substantive policy concerns related to the impacts of COVID-19 may be most fruitfully pursued in conversations initiated in relation to that Ruling.

III. Conclusion

For the reasons stated above, MCE respectfully requests the Commission reject the protests filed by PAO and SBUA of MCE AL 45-E, Marin Clean Energy's 2021 Energy Efficiency Annual Budget Advice Letter.

Respectfully submitted,

[40] Among its efforts to determine and alleviate the impacts of COVID-19 on EE programming, MCE recently provided Recurve with secure access to EE data in order to help assess the impacts of COVID-19 on EE programming. With funding from the Department of Energy, Recurve has produced a report containing its findings entitled "Comparison Groups for the COVID Era and Beyond," available at https://groups.recurve.com/uploads/8/6/5/0/8650231/recurve_comparison_group_methods_final_report.pdf (Oct. 2020). MCE is in the process of reviewing this report.

/s/ *Jana Kopyciok-Lande*_
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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011 (Filed January 30, 2019)

OPENING COMMENTS OF THE JOINT CCAS ON BUILDING DECARBONIZATION PHASE II STAFF PROPOSAL

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October 9, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011 (Filed January 30, 2019*)*

OPENING COMMENTS OF THE JOINT CCAS ON BUILDING DECARBONIZATION PHASE II STAFF PROPOSAL

I. Introduction

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the September 24, 2020 Administrative Law Judge's Ruling Setting Prehearing Conference and Directing Comment on Energy Division Phase II Staff Proposal ("ALJ Ruling"), the Joint CCAs[1] hereby submit the following opening comments on the R.19-01-011 Phase II Building Decarbonization proposal submitted by the Energy Division ("Staff Proposal") attached to the August 25, 2020 Phase II Amended Scoping Memo and Ruling of Assigned Commissioner ("Scoping Memo"). In the opening comments, East Bay Community Energy, MCE, and Sonoma Clean Power Authority ("Joint CCAs") offer a response to the Staff Proposal set forth with as much specificity as the expedited proceeding schedule allowed. The Joint CCAs respectfully reserve the right to expand upon the issues raised in these opening comments and raise issues and arguments not addressed in these opening comments going forward.

The ALJ Ruling seeks comments on the Staff Proposal by the Energy Division, addressing (1) Incentive Layering, (2) Wildfire and Natural Disaster Rebuild Program, and (3)

[1] The Joint CCAs consists of the following Community Choice Aggregation ("CCA") programs: East Bay Community Energy ("EBCE"), MCE, and Sonoma Clean Power Authority ("SCP").

Baseline Modifications for Residential Ratepayers. The following comments presented by the Joint CCAs will address all three parts of the proposal. The Joint CCAs present the following comments based on a unique set of lessons learned and experiences from energy efficiency and decarbonization programs developed and implemented by CCAs.

II. Joint CCA Responses to Questions Regarding the Incentive Layering Proposal. Joint CCAs provide the general comments on incentive layering and specific questions below.

Overall, the Joint CCAs support staff's incentive layering proposal due to the need of a concerted effort "to reduce appliance and installation costs to a level at which customers are willing to pursue fuel substitution" and ultimately, all-electric construction.[2] However, the Joint CCAs believe there is additional opportunity to inform program rules and attribution measures. The Joint CCAs respond to select questions on incentive layering from the ALJ Ruling below.

Question A.1. How should incentives from different programs to advance building decarbonization be layered?

Response: The Joint Parties find that the staff proposal on incentive layering is sufficient to protect ratepayers while appropriately capturing and apportioning attribution for installed measures. The incentive layering proposal should be clear, streamlined, and easy to execute to allow both a smooth process during program implementation but also an equal and reasonable sharing of measure benefits across programs. To achieve streamlined delivery of the program, the Joint CCAs propose that each program should receive the full benefits of the measure as calculated according to each program's underlying resource requirements (i.e. avoided energy for the EE baseline, storage benefits for SGIP, greenhouse gas benefits for TECH.) The Joint CCAs suggest that program evaluation could specifically explore whether the multiplier approach has succeeded in effectively encouraging fuel substitution and greenhouse gas reductions while providing sufficient ratepayer protections. This incentive layering approach could be adjusted in future years of implementation based on the outcome of that analysis.

[2] Staff Proposal p. 16

To further encourage streamlined delivery of incentives to customers and contractors, the Joint CCAs recommend that if TECH incentives are layered on top of rebates available through an energy efficiency program, the energy efficiency program should serve as the "front end" responsible for communicating and delivering the layered incentive to the customer. The TECH program should track layering, attribution, and drive customers toward existing electrification or energy efficiency incentives and programs.

Question A.4. Should the incentive layering guidelines address incentives provided under programs outside of the Commission's jurisdiction? If yes, how should the Commission approach or manage this?

Response: The Joint CCAs recommend that all relevant programs be included in the layering process- including CCA programs not overseen by the Commission. Coordination across the many entities administering incentives could be challenging, particularly as many agencies not subject to CPUC jurisdiction are currently offering incentives for building electrification. The staff proposal suggests that the TECH implementer should lead the development and execution of a Memorandum of Understanding among locally-regulated entities, such as Community Choice Aggregators or Municipal Utilities, for electrification incentives. The staff proposal suggests that the proposed MOU could work to ensure entities outside of CPUC jurisdiction are in alignment with state objectives. This MOU would represent a voluntary submission by locally-regulated entities as well as increased time and effort on the part of these entities; therefore, the Joint CCAs recommend that the MOU should also work to serve the interests of these entities and their customers. This could be accomplished through the sharing of key information, including appliance adoption rates, program costs and benefits, and potential load implications of newly electrified end uses, including the impacts of any associated load modification approaches. The group can identify data gaps to maximize participation in energy efficiency and decarbonization programs.

Question A.6. To establish the most effective market signal and program evaluation structure, should Energy Efficiency programs always serve as the incentive "baseline" from which other adjust incentive amounts to, or should the incentive "baseline" be based on the program that can provide the greatest incentive value

Response: The CPUC should not change the underlying baseline for any program; rather, each program should be able to apply its own cost or benefit framework to the proportion of costs and savings attributed to the program. Furthermore, the layering of incentives should not reduce the credit that each program is allowed to claim for incentivizing the measure. Doing so could have a counter-productive impact on the adoption of electrification measures. If energy efficiency programs are required to share attribution for electrification measures it could reduce the cost effectiveness of those measures to the point that they are no longer able to be offered in energy efficiency program. Under the methodology for determining TRC, an increase in incentive has a much smaller negative impact on cost effectiveness than a proportional decrease in claimable savings. For energy efficiency programs it would be more cost effective to increase incentives within the program than to "accept" a layered incentive and share savings attribution.

Electrification measures are early in the adoption curve, and the CPUC should consider how to scale the deployment of these measures over the period of the TECH program. Given the early phase of technology saturation, it is appropriate to allow the TECH program to function as a market transformation program, and for the associated cost-effectiveness methodology to mirror that proposed in the Market Transformation program framework adopted by the CPUC.[3]

Question A.8. Should any incentive layering attribution formula take into consideration measures necessary to install a technology, such as an electrical panel or 220v electrical circuit for heat pump water heaters? Should any incentive layering attribution formula take into consideration measures that enable additional performance, functionalities, such as a CTA-2045 universal communication module, which can enable load shifting and load shed for heat pump water heaters?

Response: Allowing electric service upgrades as an eligible incentive expense will help the CPUC achieve its goals for end-use electrification and these measures should be included for attribution where they allow a project that would not otherwise have happened. Currently, many single-family residential homes do not have sufficient capacity within their electric service to take on additional electrified end-uses without requiring upgrades. These unanticipated upgrades

[3] D.19-12-021 Decision Regarding Frameworks for Energy Efficiency Regional Energy Networks and Market Transformation

- often costing a few thousand dollars - can serve as a significant disincentive to end-use electrification, particularly when the cost is incurred as part of an emergency replacement of a failed appliance. Upgrading the electric service can not only pave the way for appliance electrification but can also facilitate the installation of electric vehicle infrastructure in the future, and thus should be a priority for the CPUC. The Joint CCAs agree that incentive layering should include investments that create additional value or enable a project to happen and that these measures should be eligible for attribution.

Similarly, load management devices offer an important strategy in ensuring that newly electrified end-use appliances do not exacerbate the issue of evening peak demand. These devices offer additional incremental benefits to ratepayers beyond the energy savings and greenhouse gas reduction benefits associated with end-use electrification and will be a key strategy to capturing the full greenhouse gas benefits possible with building electrification. Despite the clear benefit to the electric system from installing these devices, few homeowners are likely to include these measures in their projects of their own accord. These measures should be eligible both for incentives as well as for attribution as they represent significant potential benefit to ratepayers and are not likely to be installed as part of a project scope without financial incentives.

III. Joint CCA Responses to Questions Regarding the Proposed WNDRR Program. Joint CCAs provide the general comments on the WNDRR Program and specific questions below.

The Commission proposed the Wildfire and Natural Disaster Resiliency Rebuild (WNDRR) program "to provide incentives to help single-family homeowners and multi-family properties impacted by a natural disaster rebuild all-electric" while meeting California's climate goals.[4] The Joint CCAs support the WNDRR program to expeditiously deploy relief programs for communities who have been deeply affected by a natural disaster event such as a wildfire. To ensure that the WNDRR program meets its first principle - *Customer First*, the Joint CCAs request that the staff proposal incorporate the following comments.[5]

[4] Staff Proposal Post-Wildfire Reconstruction p.5
[5] Staff Proposal p. 28

Question B.1. Should the Commission implement any programs dedicated specifically to support the construction of decarbonized buildings in communities affected by wildfires and other natural disasters? If yes, should the Commission adopt the Wildfire and Natural Disaster Resiliency Rebuild (WNDRR) program proposed in the Phase II Staff Proposal? What, if any, modifications should be made?

Response: The Joint CCAs support the construction of decarbonized buildings in communities affected by natural disasters such as wildfire and appreciate the thoroughness of the Wildfire and Natural Disaster Resiliency Rebuild (WNDRR) program proposed by staff. The Commission should adopt the WNDRR program with the following adjustments, which are based on the insight from Sonoma Clean Power Authority and MCE's successful Advanced Energy Rebuild programs.

The Joint CCAs request that in affected areas where a CCA is established, a CCA, local government, and community-based organization (CBO) should be included on the team, unless either one of those parties declines to participate. Collaborating with a CBO is an essential part to program adoption and the deployment process. Communities and individuals experiencing grief or loss are in search of a trusted partner, to which a CBO can support this role. In order to properly evaluate the project expenses, the Joint CCAs request that the program team separates resource expenses versus the non-resource expenses so that programs can be evaluated both with and without the non-resource spend and PAs are not penalized for offering this important service. The Joint CCAs recognized that the work facilitating this type of program could impact non-implementation costs such as addressing emotionally difficult topics.

In regards to the staff proposal, GHG emission reductions are to be calculated using the reporting output from the CEC's California Energy Code Compliance Residential modeling software (CBECC-Res, CBECC-Comor, and other approved compliance software).[6] The Joint CCAs agree with this methodology, but propose that, in order to speed program deployment and encourage wider participation, the CPUC should work with the developers of CBECC and other approved compliance software to ensure that greenhouse gas emissions associated with a natural gas baseline are included in an all-electric energy model. As it currently stands, a Certified

[6] Staff Proposal WNDRR Program Incentives p. 32

Energy Auditor (CEA) would need to run two separate energy models to calculate this difference in emissions, which may have significant cost and time implications for program participants. The Staff Proposal suggests CEAs be under contract of the WNDRR implementer to provide technical assistance and modeling expertise to participants of the WNDRR program. The Joint CCAs support the inclusion of CEAs to assist homeowners wanting to participate in WNDRR. During CPUC's September 15, 2020 wildfire rebuild panel, Sonoma Clean Power Authority presented its lessons learned on the development of the Advanced Energy Rebuild program. The active engagement from CEAs can strongly influence the project's outcomes. In particular, SCP's experience was that a shortage of local CEAs in relation to the sheer number of homes lost led to a bottleneck of projects. Due to the number of projects they had to take on, local CEAs were not afforded the time to be advocates for the Advanced Energy Rebuild program. Any steps that the CPUC can take, therefore, to expand the base of qualified CEAs that may work with the WNDRR program will be valuable. Furthermore, the CPUC should also work with CABEC to provide a training plan to increase the number of CEAs in high fire threat areas.

> *Question B.6. Is the kicker incentive for passive house certification reasonable, or should the Commission consider other kicker incentives that can provide both near- and long-term benefits?*

Response: The Joint CCAs appreciate the Passive House certification, and in particular the potential for Passive House to create resilient, energy efficient, and safe homes. However, Passive House certification can be a time-intensive process and may be better suited for new construction programs that are not focused on rebuilding lost homes. To better meet California's long term objectives and make the WNDRR program accessible to more Californians, the Joint CCAs recommend an additional kicker incentive be provided for homes that either pair storage and/or load control devices with all-electric homes or achieve an air leakage target of 0.6 ACH50 - equivalent to Passive House requirements.

IV. Joint CCA Responses to Questions Regarding the Proposed Rate Adjustment for Electric Water Heating Customers. Joint CCAs provide the general comments on the baseline modification and specific questions below.

The Staff Proposal recommends the three large electric IOUs to "introduce a new baseline allowance for customers who install electric water heating equipment" encouraging building and home decarbonization.[7] The Joint CCAs recognize the existing disincentive to electrification of water heaters and support this need for updated rate design. In addition to a rate structure, the Joint CCAs find it important to ensure customers' baselines are adjusted by the PA.

Question C.1. Should the Commission require electric Investor-Owned Utilities (IOUs) to provide a special baseline allowance for residential customers who install electric water heating equipment in order to facilitate the decarbonization of buildings?

<u>Response:</u> The Commission should require IOUs to provide a special baseline allowance for residential customers who install high-efficiency electric water heating equipment in order to facilitate a decarbonized future. In addition, the Joint CCAs support the recommendation in the Staff Proposal that a more comprehensive electrification rate design be taken up in Phase IV of the General Rate Case, yet encourage the IOUs to include CCAs as key stakeholders on electrification rate design.

As noted in the staff proposal, heat pump water heaters (HPWHs) represent a cost-effective intervention with immediate GHG reduction potential. However, currently customers could be penalized for transitioning to a HPWH if their baseline allocation of electricity consumption is not adjusted to account for the newly electrified load. This could have the unintended consequence of increasing customer costs.

The Joint CCAs urge the CPUC to direct the IOUs to work with CCAs in their service area on rate development, particularly electrification rate development. CCAs are highly motivated to achieve carbon reductions through building electrification and represent a significant portion of California's ratepayers. They are thus key stakeholders in the design of rates intended to address electrification and should be included to ensure that new rates will work for CCAs as well. For example, ensure TOU periods match, rates are not anti-competitive, and that there are no cost allocation concerns.

The Joint CCAs recommend that the IOUs should be directed to create a streamlined process by which a program administrator could ensure that the customer's baseline is automatically

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7 Staff Proposal Baseline Allowance Modification p. 6

adjusted post-HPWH install. Furthermore, a program administrator that incentivizes electrification measures should be responsible for working with the IOU to update the baseline. This would avoid any customers being left on a more expensive rate because of a lack of knowledge or capacity to request the adjustment themselves. For example, MCE partnered with the CPUC and PG&E to adjust customers to an electric heating baseline through the Low-Income Families and Tenants (LIFT) program. MCE's Low-Income Families and Tenants (LIFT) Program is a pilot in the ESA proceeding offering in-unit incentives for income-qualifying multifamily energy efficiency upgrades and low-cost to no-cost heat pumps for water and space heating and cooling.[8] In addition to providing affordable access to electrification, the LIFT program offered additional assistance to properties in switching to an electric heating baseline once the property had upgraded to all-electric heat pumps. This process, which normally is conducted over the phone by the individual residents, is being done property-wide, thanks to collaboration between MCE and Energy Division. This assistance enabled residents to take advantage of these rates without any additional burden on their part.

V. Conclusion

The Joint CCAs appreciate the opportunity to provide comments on the Phase II Building Decarbonization Staff Proposal and look forward to an ongoing dialogue with the Commission and stakeholders on these issues.

Respectfully submitted,

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[8] D.16-11-022 p. 387

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Exhibit No.: (MCE-2)
Date: October 9, 2020
Witness: Alice Havenar-Daughton

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

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1. Introduction

On September 4, 2020, several parties to this proceeding submitted testimony responding to the applications of MCE and the IOUs. Many parties made observations and recommendations about MCE's Low-Income Families and Tenants ("LIFT") program, to which MCE appreciates the opportunity to respond.

Many parties observe that the ESA program could benefit from significant structural improvements, and several parties recommend best practices that LIFT already employs, including third-party implementation, a robust Single Point of Contact model with extensive opportunities for program leveraging, fuel-switching, a comprehensive, whole building approach, and flexibility for participating properties. Several parties also agreed that the current ESA income threshold of 200% of the Federal Poverty Level does not adequately meet the needs of low-income Californians.

At the same time, testimony on behalf of the Public Advocates Office ("PAO") indicates that additional clarity may be needed regarding several aspects of LIFT, including its Pilot project timelines and the way that MCE calculates and reports LIFT's energy savings goals and performance. MCE appreciates the opportunity to clarify the LIFT program in this rebuttal testimony.

Additionally, MCE appreciates the opportunity to address the challenges LIFT has faced around using the ESA Cost Effectiveness Test ("ESACET"), which impact the program as a whole but also directly impact MCE's LIFT application, as PAO has noted. MCE would appreciate the opportunity to accurately apply the ESACET to the LIFT 2.0 application, but as discussed below has been unsuccessful in gaining access to the tools and information needed to do so.

Finally, the question of whether and how to approach treating Naturally Occurring Affordable Housing ("NOAH") is a challenging but necessary one, and the consequences of moving too quickly must not be underestimated. At the same time, MCE does not believe that continuing to exclude residents of NOAH properties from receiving LIFT or ESA treatment is a viable path forward. California must identify a solution to this problem if we are to best serve our low-income families, and also achieve our statewide energy and greenhouse gas emissions ("GHG") reduction targets.

2. LIFT Offers Several Program Design Features that Parties Identify as Best Practices

In their testimony, several parties described best practices and model programs, especially serving the multifamily sector, both in and outside of California. These parties, including the Natural Resources Defense Council ("NRDC") and National Consumer Law Center ("NCLC") (together, the "Joint Parties"), and The Utility Reform Network ("TURN"), made recommendations for evolving the ESA program to incorporate these best practices.

MCE's LIFT 2.0 application includes many of the program design features identified by parties as best practices, including a robust Single Point of Contact ("SPOC"), a whole-building approach, building electrification, and flexibility for participating property owners.

a. A Robust Single Point of Contact That Seamlessly Leverages Multiple Programs

Both TURN and the Joint Parties identified a robust SPOC as an essential best practice for effective programs delivering deep savings to multifamily properties. A robust SPOC goes beyond a referral service, providing a comprehensive whole building energy audit, behind-the-scenes coordination of incentives available through multiple programs supporting health and safety as well as energy savings, and comprehensive, expert technical assistance throughout the process.

The Joint Parties note that the California Energy Commission's 2016 SB 350 Barriers Study identified challenges regarding program coordination and leveraging of multiple funds as a barrier to deeper energy savings as well as more comprehensive health, safety and comfort benefits.[1] The Joint Parties describe multiple programs that they characterize as model programs for their ability to address these barriers while minimizing the burden on participating properties to the greatest extent possible.[2] These model programs do so by, among other things, utilizing a robust SPOC that functions as a one-stop-shop for participating properties.[3] Additionally, TURN notes that a single point of contact is a characteristic of top-performing low-income energy efficiency programs, according to a nationwide study conducted by the American Council for an Energy Efficient Economy ("ACEEE").[4]

The Joint Parties note that LIFT offers an effective programmatic approach to leveraging funding, by seamlessly integrating rebates from multiple programs including those that fund health and safety upgrades.[5] The Joint Parties characterize LIFT as exemplifying best practices, in part for its "hybrid" model that leverages funding opportunities from multiple sources, reducing administrative burden for the property owner and allowing the program to deliver significant energy savings as well as decarbonization through fuel switching.[6]

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[1] Opening Testimony of Jeanne Clinton and Lara Ettenson for the Joint Parties, p. 6, citing Scavo, Jordan, Suzanne Korosec, Esteban Guerrero, Bill Pennington, and Pamela Doughman. 2016. *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-income Customers and Small Business Contracting Opportunities in Disadvantaged Communities*. California Energy Commission.
[2] Opening Testimony of Lindsay Robbins for the Joint Parties, pp. 13-15, and Opening Testimony of Andrew Brooks for the Joint Parties, pp. 9-14.
[3] Opening Testimony of Lindsay Robbins for the Joint Parties, pp. 13-15.
[4] Opening Testimony of Alice Napoleon for TURN, pp. 35-36.
[5] *Id.* at p. 13.
[6] Opening Testimony of Andrew Brooks for the Joint Parties, pp. 13-14.

For these reasons, MCE intends to continue its robust SPOC model in LIFT 2.0. Depending on the participating property's level of interest, LIFT's SPOC can incorporate ESA funds, general market energy efficiency funds, solar incentives, EV charging infrastructure incentives, MCE Healthy Homes funds,[7] and storage incentives through the Self Generation Incentive Program ("SGIP") into the same project. Under this model, the program implementer identifies all available incentives for the upgrades the property wishes to pursue, and prepares for the property owner a combined project proposal that details the work to be done, the anticipated energy savings, the available incentives, and the owner's out-of-pocket costs. For all work the owner chooses to pursue, the program implementer applies for the available incentives on the property's behalf. Upon completion of the project, the program implementer provides easy-to-understand tenant education that is customized to the measures the property elected to install. In LIFT 2.0, MCE proposes to include education tailored to time-of-use prices, as the transition is anticipated to occur during the 2021-2026 program cycle.

By taking as much work as possible off of the owner and residents, LIFT's SPOC model increases the property's ability and willingness to undertake a whole building project. This model leverages the program implementer's expertise in both building performance and California policies, programs, and funding opportunities. A robust SPOC maximizes savings and other benefits for the property, while working within the property's budgetary and scheduling constraints.[8]

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[7] For more information on the Green and Healthy Homes Initiative partnership in Marin County, of which MCE is a member, see MCE's Opening Testimony on LIFT 2.0 at p. 10. As described on p. 39 of MCE's Opening Testimony, LIFT 2.0 will expand the GHHI partnership model to Contra Costa County, with a focus on asthma mitigation.
[8] *See also* Opening Testimony of Andrew Brooks for the Joint Parties, pp. 6-8.

b. A Comprehensive Whole Building Approach

In addition to a robust SPOC that can leverage multiple programs and funding sources, the Joint Parties note that a whole building approach is a best practice for the multifamily sector.[9] The Joint Parties state that, for multifamily properties, a whole building approach is the most effective model for reducing tenants' energy costs, as well as building energy usage and greenhouse gas ("GHG") emissions.[10] The Joint Parties also note that treating a whole building comprehensively costs less in the long run than multiple partial treatments to the same property, and achieves tenant bill savings all at once, rather than incrementally over time.[11]

By offering both common area and in-unit measures as part of the same comprehensive process (described above), LIFT makes it easier for property owners to undertake a whole building upgrade. The Joint Parties note that, in practice, LIFT's ability to layer ESA funds on top of general market energy efficiency funds results in more in-unit upgrades than the property owner may otherwise be able to afford.[12]

c. Building Electrification through Fuel Switching

MCE has offered fuel switching as part of LIFT since its inception, and intends to continue to do so in LIFT 2.0. In addition to supporting key state policies,[13] fuel switching supports MCE's own agency goals regarding GHG emissions reduction.[14] TURN notes that "electrification of

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[9] *Id.* at pp. 4-6.
[10] *Id.* at p. 4.
[11] *Id.* at p. 5.
[12] *Id.* at 13.
[13] SB 32 (Pavley) establishes a statewide GHG reduction target of 40% below 1990 levels by 2030. Executive Order S-3-05 (2005) establishes a statewide GHG reduction target of 80% below 1990 levels by 2050.
[14] MCE's mission is to address climate change by reducing energy-related greenhouse gas emissions with renewable energy and energy efficiency at cost-competitive rates while offering economic and workforce benefits, and creating more equitable communities. *See* https://www.mcecleanenergy.org/about-us/.

buildings is likely to be the least-cost means of decarbonizing the building sector."[15] TURN also notes that electrification also avoids locking low income customers and affordable properties into a fuel that will only become more expensive during the life of the measure.[16]

In MCE's experience with the LIFT Pilot, heat pumps have been very popular even though LIFT does not cover the full cost of the measure. Heat pump water heaters are appealing because of the savings they deliver for owners and tenants. Heat pumps for space conditioning are appealing because participating properties want to upgrade their heating and also add cooling – both of which a heat pump for space conditioning can provide. After the Bay Area's recent unprecedented heat waves, MCE anticipates that the appetite for multifamily property owners to add cooling will only increase, especially in the warmer parts of MCE's service area in Contra Costa, Solano, and Napa counties. Finally, both types of heat pumps are appealing because they eliminate the health and safety risks associated with gas leaks.

MCE is awaiting analysis from its 3rd party EM&V consultant on the first 12 months of heat pump usage in LIFT participating properties. This analysis will demonstrate the performance, bill impacts, and energy consumption of both space and water heat pumps installed during the first year of the LIFT Pilot. This analysis compares normalized pre- and post- installation usage data, and must be captured during all seasons to accurately and completely capture the measure's performance. As such, one full year of post-installation data is needed. MCE plans to include this data in its final report of the LIFT Pilot, scheduled for release three months after the conclusion of the Pilot.

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[15] Opening Testimony of Alice Napoleon for TURN, p. 44, citing Energy and Environmental Economics, Inc, *The Challenge of Retail Gas in California's Low-Carbon Future* (CEC-500-2019-055-F), prepared for the California Energy Commission, April 2020.
[16] Opening Testimony of Alice Napoleon for TURN, pp. 46-47.

d. Flexibility for Participating Property Owners

Testimony for the Joint Parties notes that offering flexibility to owners is a best practice for multifamily properties.[17] The LIFT Pilot has offered flexibility by providing participating properties their choice of contractor, so long as the contractor meets applicable safety and certification standards, and choice of equipment, so long as it meets applicable standards for efficiency and performance. MCE intends to continue offering these choices to participating property owners in LIFT 2.0. MCE has found that property owners are more invested in a project when they are empowered to choose their contractor(s) and equipment. This leads to greater satisfaction with the project and increases the likelihood that they will participate in additional clean energy upgrade opportunities, and/or share a positive referral with other property owners.

Many property owners participating in LIFT already have a relationship with one or more contractors that can do most, and in some cases all, of the work involved in the project's scope.[18] Those that do not, or that need to find a specialized contractor for a portion of the project, generally prefer to select a contractor themselves, with technical assistance provided by the program implementer. While MCE does not assume that all property owners share this preference, in MCE's experience with the LIFT Pilot, many owners prefer to use the contractors they use for other kinds of work on their properties.

3. Broad Support for an Income Eligibility Threshold that Better Serves Low Income Californians

In their testimony, several parties noted that the current ESA income threshold of 200% of the Federal Poverty Level ("FPL") is insufficient to properly serve California's low-income

[17] Opening Testimony of Lindsay Robbins for the Joint Parties, pp. 5-6, and Opening Testimony of Andrew Brooks for the Joint Parties, pp. 8-9.
[18] *See* also Opening Testimony of Andrew Brooks for the Joint Parties, p. 6.

communities, particularly in more expensive areas of the state. The Energy Efficiency Council ("EEC") and La Cooperativa Campesina de California, Maroma, and Proteus all submit that the current income threshold is not appropriate for California, because of our state's high cost of living as compared to a federal standard, and as a result excludes many low-income households from participation.[19] Both the Joint Parties and EEC observe that the current ESA income threshold creates a barrier to whole-building treatment even for deed-restricted affordable properties, because those properties use an Area Median Income ("AMI") threshold.[20] The Joint Parties also note that using an AMI-based income threshold will ease the administrative burden for participating property owners, as they are more likely to have information on their tenants' incomes relative to AMI than to FPL.[21]

These testimonies align with MCE's experience. The current threshold leaves out many Californians that by any other measure are low-income, and that struggle to afford their monthly energy and other household bills. Like the parties cited above, MCE too has found that the current income threshold makes it exceedingly difficult to provide whole building treatment even to deed restricted affordable housing properties, which typically use an 80% AMI income eligibility threshold. Finally, the current income threshold makes it difficult to leverage funds like Solar on Multifamily Affordable Housing ("SOMAH") for solar and SGIP for storage that use 60% AMI as their income threshold. These barriers led MCE to propose in its application that the Commission allow MCE to use 60% AMI as the income threshold for LIFT, but as a matter of policy MCE supports making this adjustment for the ESA program statewide. MCE would also

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[19] Opening Testimony of Allan Rago for EEC, pp. 7-9, and Opening Testimony of Robert Del Real for La Cooperativa Campesina de California, Maroma and Proteus, p. 5.
[20] Opening Testimony of Jeanne Clinton and Lara Ettenson for the Joint Parties, p. 13-14, and Opening Testimony of Anna Solorio for EEC, p. 6.
[21] Opening Testimony of Lindsay Robbins for the Joint Parties, pp. 16-17.

support adjusting the income threshold for ESA statewide, including LIFT 2.0, to the low-income definition used by the California Department of Housing and Community Development, as EEC proposes.[22]

4. MCE's Proposed Savings Goals Are Based on Correct, Leveraged Calculations

PAO characterizes the savings goals set forth in MCE's LIFT 2.0 application as being incorrect, because they are based on savings achieved by measures supported by general market energy efficiency funds (through MCE's Multifamily Energy Savings program ("MFES")) as well as those supported by ESA funds.[23] PAO's description of the way the savings goals are calculated is correct, but its characterization of these goals as incorrectly calculated is inappropriate.

As discussed above in Section 2, one of the key features of both the LIFT Pilot and the LIFT 2.0 application is the seamless behind-the-scenes integration of multiple program funds in one holistic project. MCE has found this approach to be well-received by property owners, as well as a more effective way to perform deeper retrofits and achieve greater savings. Several parties also note this model as a best practice for serving the multifamily sector in their opening testimony. Finally, the Energy Division Staff Report identifies greater program leveraging as one of its three cornerstone goals.[24]

The savings goals stated in the LIFT 2.0 application are correct for the way that LIFT is designed, as a program that leverages multiple funding streams. However, MCE acknowledges that this unique design can create some confusion when attempting to discern what level of savings each funding stream is achieving. While the savings goals set forth in the LIFT 2.0 application are correctly *calculated*, MCE acknowledges that the way these goals are *presented* has created some

[22] Opening Testimony of Allan Rago for EEC, p. 9.
[23] Cal Advocates-3, p. 11.
[24] Energy Division Staff Proposal - June 2020 Energy Savings Assistance Program Goals for Years 2021-2026, p. 4.

confusion. MCE agrees that breaking out each funding stream's projected savings, in addition to reflecting the combined savings LIFT can achieve through its leveraging model, would be helpful for a variety of analyses.

However, it is important to note that one of the key learnings to be derived from the LIFT Pilot as well as from LIFT 2.0 is how behind-the-scenes program leveraging and integration works as a strategy for achieving deep energy savings and decarbonization in the low-income multifamily sector. As such, an analysis that is limited only to how the ESA-funded measures in LIFT compare to the IOU ESA programs will miss the bigger picture. In order to learn fully from LIFT, and to answer many of the questions posed by PAO and others about the future of ESA, analysis must include but also go beyond this strict 1:1 comparison.

Broken out by funding stream, not including savings associated with fuel substitution, the savings goals for LIFT 2.0's are as follows:

	PY1	PY2	PY3	PY4	PY5	PY6	Total
LIFT kWh	14,403	34,566	48,969	51,849	51,849	51,849	253,484
MFES kwh	104,098	249,834	353,932	374,751	374,751	374,751	1,832,116
kWh Total	**118,500**	**284,400**	**402,900**	**426,600**	**426,600**	**426,600**	**2,085,600**
LIFT therms	3,598	8,634	12,232	12,951	12,951	12,951	63,316
MFES therms	11,321	27,168	38,488	40,752	40,752	40,752	199,232
Therms Total	**14,918**	**35,802**	**50,720**	**53,703**	**53,703**	**53,703**	**262,548**

Figure 1: LIFT Energy Savings Goals by Funding Stream

Because LIFT projects include both ESA-funded and MFES-funded measures, both these goals and the Pilot results cited in PAO's testimony[25] are reasonable. MFES, as a general market energy efficiency program, is subject to higher cost effectiveness standards than ESA. As such, when the property owner and program implementer are determining the best package of measures

[25] Cal Advocates-3, p. 12, citing MCE's LIFT Interim Report, Table 3.

and incentives for the property, it is reasonable for the more cost-effective measures to be supported by MFES funds.

ESA, on the other hand, includes support for measures that do not deliver cost-effective energy savings but do increase health, safety and comfort. Often, ESA is the only available funding source to help properties afford these upgrades. Many of LIFT's participating properties are senior housing, and/or are owned by nonprofit, mission-driven organizations that want to provide a healthy and comfortable home for their residents. They are all operating on very limited budgets, and appreciate the opportunity LIFT provides to invest in in-unit health, safety and comfort improvements.[26] As such, it is reasonable for the property owner and program implementer to choose to support equity measures through ESA funds. While this choice naturally impacts the energy savings performance of ESA-funded LIFT measures, it also supports ESA's equity and hardship reduction goals.[27]

Because of LIFT's program leveraging model, participating properties still achieve significant energy savings, as noted in the LIFT Interim Report cited by PAO. Should the Commission adopt the goals set forth in the Energy Division Staff Proposal, which include more effective leveraging of complementary programs, results based on the combined impact of multiple programs may become the norm.

[26] As discussed below in Section 6, ongoing challenges regarding the valuation of non-energy benefits and access to the tools needed to calculate ESACET values make it difficult for MCE to accurately determine the full value of these measures.
[27] Cal. Pub. Util. Code Section 2790(a).

5. MCE Will Provide Support for Its Savings Goals for Eligible Measures Through its Proposed Public Process for Measure Selection

PAO notes that MCE did not provide workpapers or other documentation in support of its stated savings goals for LIFT 2.0.[28] PAO also notes that MCE did not provide a preliminary list of measures, and an analysis of whether the measures proposed for LIFT 2.0 are different from those adopted in the LIFT Pilot.[29]

As described in MCE's LIFT 2.0 application, MCE proposes to conduct a public stakeholder process with its competitively-selected program implementer to identify, evaluate, and finalize the ESA-funded measures LIFT 2.0 will offer.[30] MCE proposed this model in order to ensure that the measures LIFT 2.0 will offer are the best options available at the time the program will begin serving customers.

Applications in this program cycle were filed November 4, 2019. It took MCE approximately 4 months to prepare this application, which means that if MCE were to have included a preliminary measure list, that list would likely have been created in the summer of 2019. The most recent set of low-income programs applications, A.14-11-007 et. al., took two years to resolve.[31] Once a final decision is approved, MCE must conduct a competitive solicitation for a program implementer, which typically takes 4-6 months from solicitation to contract execution. Added together, these processes mean that a measure list created in the summer of 2019 may not be implementable until late 2021 or early 2022, creating a time lag of nearly three years.

[28] Exhibit Cal Advocates-3, p. 13.
[29] *Id.*
[30] Testimony of Marin Clean Energy, Exhibit MCE-1, p. 44.
[31] Applications were filed on November 18, 2014 and D.16-11-022 was issued on November 21, 2016.

A lot can happen in three years in California's energy efficiency programs landscape. Common changes include new funding streams to support new technologies, significant performance improvements or cost reductions for existing technologies, EM&V results that impact claimable savings, and legislation impacting core aspects of program design or delivery, such as changes to codes and standards. As a result, a measure list created nearly three years before program implementation begins may require significant changes at implementation time in order to ensure that the program is as effective and cost-effective as possible. The public process MCE proposes for determining the appropriate ESA-funded measures to include in LIFT will be a more efficient way to compile a measure list that better reflects the energy and building performance landscape at the time the program opens.

During this public process, MCE and the LIFT third party implementer will propose a preliminary measure list, including supporting documentation. As noted in LIFT testimony, this is standard practice for third party implemented programs,[32] because it capitalizes on the implementers' expertise and eliminates the impacts of long procedural and administrative timelines, as described above.[33] MCE encourages interested stakeholders, including CPUC staff, to participate in the process, and will incorporate stakeholder feedback in its final measure list. The measure list will also include supporting documentation such as workpapers or deemed savings values. As discussed in greater detail below in Section 7, it may be reasonable for MCE to submit its final measure list for Commission review via an Advice Letter.

[32] Testimony of Marin Clean Energy, MCE-1, p. 45.
[33] Of note, PAO describes 3rd party implemented programs as superior to the current ESA model because, among other reasons, they provide better transparency and competitive benefits, in addition to encouraging deeper savings. PAO advocates that the full ESA program should move to a 3rd party designed and implemented model. *See* Cal Advocates-4, pp. 5-6.

6. MCE Supports Greater Transparency for ESACET Calculations and Methodology

PAO notes that MCE is unable to provide ESA Cost Effectiveness Test ("ESACET") values for the LIFT Pilot or for individual measures.[34] PAO also notes that there are problems with existing models for valuing non-energy benefits ("NEBs"), and that the NEB models are highly complex and technical.[35]

MCE agrees with all of the above assertions. MCE has indeed been unable to calculate the ESACET values for its Pilot or for the LIFT 2.0 application, because 1) accurate NEB data is unavailable to MCE, and MCE does not have the in-house capacity to attempt to create NEB values with sufficient accuracy to include in an application; and 2) MCE is unable to either access or create an ESACET calculator. MCE would greatly appreciate the opportunity to access the tools and information needed to provide ESACET values to the Commission and to stakeholders.

As described in PAO's testimony, the APPRISE report, due in November of this year, will hopefully address the current challenges with inconsistency and lack of transparency in NEB values and calculations.[36] It is MCE's understanding that the IOUs used modified versions of earlier NEB values to calculate their ESACET values,[37] but as PAO notes, it's not clear from their testimony what modifications were made.[38] Without access to reliable NEB values and without the in-house capacity to perform the kinds of updates described in the IOUs' applications, MCE is missing a critical component of the ESACET.

Further, MCE does not have access to the ESACET calculator. Where the CPUC has made the cost effectiveness calculators used for general market EE programs publicly available for all

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[34] Cal Advocates-2, p. 25, and Cal Advocates-3, p. 13.
[35] Cal Advocates-2, p. 25.
[36] Cal Advocates-2, pp. 22-24.
[37] Opening Testimony of PG&E, pp. I-111 – I-112.
[38] Cal Advocates-2, p. 25.

stakeholders to review, and all program applicants and participants to use,[39] the same is not true for the ESACET. It is MCE's understanding that the ESACET calculator is built by using the Low-Income Public Purpose Test ("LIPPT") workbook, created in 2001,[40] and making certain updates to it to render it more current. It is MCE's understanding that each IOU undertakes these updates independently. While the LIPPT report is publicly available,[41] the Excel-based calculator tool is not. With neither the original workbook to start with, nor clear guidance about how to correctly update the original workbook, it is virtually impossible for MCE to perform ESACET calculations.

The Commission should make the ESACET calculator publicly available, just as it has done with the cost effectiveness calculators for the general market EE programs. This will ensure that all applicants are using the same model in the same way, and allow stakeholders much greater insight into these important calculations. This will also allow MCE to perform ESACET calculations for both the LIFT Pilot and LIFT 2.0.

7. It Is Not Reasonable to Reduce MCE's Budget Request for LIFT 2.0 at This Early Stage

PAO argues that LIFT 2.0 should be authorized for a budget of $1.3 million now, which is equal to the amount the LIFT Pilot had spent as of May 2020.[42] PAO submits that MCE should be permitted to request a budget increase via Tier 3 AL after the Pilot has undergone a complete

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[39] The cost effectiveness calculators, created by Energy and Environmental Economics ("E3") are available at the following link, which can be accessed from the CPUC's Energy Efficiency website: https://www.ethree.com/public_proceedings/energy-efficiency-calculator/.

[40] *See* Cal Advocates-2, pp. 21-22.

[41] For example, the report is available in the California Measurement Advisory Council "CALMAC") database and also through. the Low-Income Oversight Board's website. *See* http://www.calmac.org/publications/Final_LIPPT_Report_v4.pdf and http://liob.cpuc.ca.gov/docs/The%20Low%20Income%20Public%20Purpose%20Test%20(LIPPT)%20May%2025,%202001.pdf.

[42] Cal Advocates-3, p. 13.

evaluation that demonstrates cost-effective savings.[43] PAO's proposal is unreasonable for the several reasons discussed below.

First, it is not reasonable to base the budget for program years 2021-2026 on the spend rate from the first two and a half years of the Pilot. As noted in the LIFT 2.0 application, it is not uncommon for projects including both in-unit and common area measures in the low-income multifamily sector to take 18 months or more from start to finish.[44] This is true not only for LIFT but across the sector. Additionally, as noted in the Joint Parties testimony, opportunities to perform a more comprehensive upgrade at an affordable multifamily property may only come around once every few years or more.[45] Taken together, the timelines inherent in doing retrofit work in the affordable multifamily sector may make progress seem slow when viewed out of context, but that is simply the normal pace of operations for comprehensive projects in this sector. MCE acknowledges that it was overly optimistic in its Pilot application about how fast it could implement these kinds of projects, but the drastic reduction to MCE's budget request proposed by PAO would be an unduly harsh response to the optimism of a new market entrant.

Second, LIFT utilizes a robust SPOC and behind-the-scenes program leveraging as its delivery model, which several parties note as a best practice.[46] This model achieves Goal #2 of the Energy Division Staff Proposal, to maximize participation in other clean energy programs that will reduce household hardship,[47] while minimizing the administrative burden for both the property owner and residents, as discussed above in Section 2. It is MCE's understanding that LIFT is the

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[43] *Id.* at 14.
[44] Testimony of Marin Clean Energy, p. 13.
[45] Opening Testimony of Andrew Brooks for the Joint Parties, p. 5.
[46] See Section 2, above.
[47] Energy Division Staff Proposal - June 2020 Energy Savings Assistance Program Goals for Years 2021-2026, p. 4.

only program under the ESA umbrella that utilizes this model, as opposed to a referral model. Because MCE is implementing a model that is held up as a best practice, and is doing so in a sector in which project timelines are fairly long, it is reasonable for the Commission to allow this model more than two and a half years to demonstrate results. Making a drastic cut to LIFT's first full program cycle, as PAO proposes, would not allow LIFT to sufficiently demonstrate all that this model is capable of.

Third, PAO's proposal introduces a degree of budget uncertainty into LIFT 2.0 that will work to stifle, rather than discipline, the program's development. It would be exceedingly difficult for MCE to undertake program launching activities, such as contracting with an implementation partner, finalizing the measures list, and building a project pipeline for LIFT 2.0 without knowing whether its budget will be $1.3 million or $10.3 million.[48] Such a severely constrained budget from the outset, even with the possibility of an expansion, would cause the LIFT 2.0 planning process to be at best overly cautious and at worst highly inaccurate and inefficient, since MCE would be almost entirely in the dark about its program budget.

Given all of the above, it is not reasonable for the Commission to drastically reduce the LIFT 2.0 budget at this early stage. If PAO's objective with this recommendation is to ensure that the LIFT 2.0 budget is prudently spent on cost-effective upgrades, it would be more appropriate for MCE to submit its final measure list and ESACET calculations, once the necessary tools are available,[49] to the Commission via Tier 1 Advice Letter. Given that this will be a 6-year program cycle, it would also be reasonable to submit periodic updates to the measure list via Tier 1 Advice Letter over the course of the program cycle, i.e. every two years. This will allow LIFT to keep its

[48] While no application's budget is ever certain until it is approved by the Commission, this degree of uncertainty would be highly unusual as well as unreasonable.
[49] As discussed above in Section 6.

measure list current while also providing some degree of stability for planning and analysis purposes.

8. MCE Agrees to Submit a JCM of Reasonable Scope Within 30 Days After Final Approval of LIFT 2.0

PAO recommends that the Commission require MCE and PG&E to submit a Joint Cooperation Memorandum ("JCM") within 30 days of the date of issuance of the final decision in this proceeding.[50] PAO recommends that this JCM contain a detailed plan to avoid duplication and reduce costs for ratepayers, and that it should specify if any existing cooperation practices would be modified for ESA multifamily whole building ("MFWB") programs. PAO recommends that the JCM should include coordination details after launch, including information about meeting frequency, what information PG&E and MCE intend to share, and a mechanism for ongoing program improvement.[51]

MCE does not object to providing this information in a JCM. However, should there be any outstanding issues to resolve regarding LIFT 2.0 after the final decision in this proceeding, it would be reasonable to allow MCE to resolve those issues first, and then create a JCM based on the final and fully approved LIFT 2.0.[52] "Starting the clock" for the JCM timeline upon final approval of LIFT 2.0, be that in the final decision or in a subsequent ruling, would be more administratively efficient and ensure that the JCM is as accurate and complete as possible.

However, PAO also recommends that the JCM between MCE and PG&E contain a research plan that evaluates the key differences between MCE's and PG&E's proposals, and

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[50] Cal Advocates-3, pp. 15-16.

[51] *Id.*

[52] MCE's LIFT Pilot was approved in D.16-11-022, issued November 21, 2016, but was not finalized until MCE Advice Letter 23-E-A was approved on August 2, 2017. While MCE does not anticipate such an outcome in this proceeding, it seems reasonable to account for the possibility.

"identify the program design that is effective and/or beneficial to participants and ratepayers."[53] PAO asserts that the results of this research could be used across ESA.[54] These are valuable questions to pose, however, this kind of study would be more useful if it was not limited to a comparison of LIFT and PG&E's MFWB program.

Because all three IOUs propose 3rd party designed and implemented MFWB programs, there may be significant differences in the way the IOU programs will end up being structured. In addition, general market energy efficiency programs are structured differently from ESA, and non-IOU programs such as the Low-Income Weatherization Program ("LIWP") also differ in key aspects of their design and implementation. MCE agrees that identifying effective program designs is a good goal and worthy of study, but it should be done more broadly and comprehensively than PAO proposes.

Further, the costs of such a study should be equitably shared across the ESA program. Since the statewide ESA program will to benefit from the findings of such a study, then it is reasonable for all ESA program administrators to share its costs. In fact, elsewhere in its testimony PAO proposes a mid-cycle review that should include analysis of the differences between programs, such as the various SPOC models and their implementation, treatment of naturally occurring affordable housing ("NOAH") properties, etc.[55] A mid-cycle review is a much more appropriate forum for these statewide program questions than a JCM between MCE and PG&E.

Additionally, PAO seems to seek the single program design that is "effective and/or beneficial to participants and ratepayers," and notes that the findings could be applicable

[53] Cal Advocates-3, p. 16.
[54] *Id.*
[55] *Id.* at pp. 18-20.

statewide.[56] In MCE's experience, *there is no single program design that fits all low-income customers*, even within a single housing sector (multifamily) in a small service area like MCE's. In a marketplace that offers multiple program models, each offering different features, customers have the benefit of choosing the model that works best for them. Some customers prefer the ease of a direct install program, whereas others want more flexibility and a greater degree of involvement in the project. Some properties may want to prioritize energy savings and bill reduction for their tenants, where others may prioritize health benefits like asthma trigger mitigation. The condition and layout of the building, and the climate in which it is located all impact what kind of program will best meet the property's needs. In MCE's four-county service area alone, a 6-unit garden-style property in western Marin County will have very different needs from a 100-unit, 10-story building in downtown Concord, and from farmworker housing in unincorporated Solano County. Rather than seeking a single program design to meet the needs of a very large, diverse state, the Commission should seek to design a menu with a comprehensive set of options.

9. In-Language Educational Materials Would Be More Relevant in MCE's Most Commonly Spoken Languages

PAO recommends that, in addition to English, educational materials should be provided to ESA customers in Spanish as well as the top three most commonly spoken languages statewide.[57] PAO notes that this requirement is in place for wildfire plan notices, and recommends it be adopted for ESA and LIFT 2.0.[58]

[56] *Id.* at p. 16.
[57] *Id.* at p. 18.
[58] *Id.*, citing Cal Pub. Util Code Section 8386(c)(16)(b).

MCE is committed to ensuring that all of its customers can benefit from energy efficiency and other clean energy services, regardless of the language they speak at home. MCE provides service to customers in 34 communities across Contra Costa, Marin, Napa, and Solano counties. While MCE will add additional communities in these four counties to its service area during the 2021-2026 program cycle, MCE does not plan to expand beyond these four counties. A requirement to translate educational materials into the most commonly spoken languages on a statewide basis could create a misalignment with the most commonly spoken languages in MCE's service area. In-language materials in the most commonly spoken languages in MCE's service area would be more relevant and cost-effective.

10. It Is Reasonable to Cautiously Explore Treating NOAH Properties with Robust Renter Protections

EEC expresses concerns with the prospect of expanding ESA to serve naturally occurring affordable housing, or NOAH properties.[59] EEC provides anecdotal evidence of two instances known to its witness,[60] but it is not clear from its testimony 1) whether these rent increases would have happened without the EE upgrades, given the nature of the CA housing market; and 2) to what extent such a phenomenon may be occurring across the state.

However, the housing market in California is unquestionably difficult for low-income families, especially those who cannot benefit from subsidized or deed-restricted affordable housing. As such, the concerns raised by EEC about the risk of displacement must be taken seriously. At the same time, MCE does not believe that declining to treat NOAH properties that meet applicable income eligibility requirements is a viable option either. Declining to treat NOAH properties would leave the majority of income-eligible renters unable to benefit from the energy

[59] Opening Testimony of Anna Solorio for the Energy Efficiency Council, pp. 8-9.
[60] *Id.*

savings and health, safety and comfort improvements LIFT can provide. It would also leave many residential properties on the sidelines of California's efforts to reduce its GHG emissions[61] and to double its energy efficiency savings from buildings,[62] because NOAH properties are unlikely to invest in significant energy efficiency measures on their own.

As such, MCE plans to venture cautiously into working with NOAH properties in LIFT 2.0. MCE will incorporate into its approach lessons learned from the San Joaquin Valley Pilots[63] as well as from LIWP[64] and other programs identified, in this proceeding as well as elsewhere, as being model programs. MCE intends to start with a small number of NOAH properties and monitor them closely post-installation to ensure that the owner is abiding by all renter protection commitments. If MCE identify any issues with our initial approach, we will adjust our approach or pause serving NOAH properties altogether, as appropriate.

11. A Reasonable Budget Allocation for Administrative Costs Should Be Determined as Part of the Broader Process of Defining the Future of ESA

PAO submits that each ESA multifamily program administrator's administrative budget should be capped at 10%, in order to maximize the budget available to support installations.[65] At the same time, it is widely acknowledged that ESA serves some of the state's most hard-to-reach

[61] SB 32 (Pavley) establishes a statewide GHG reduction target of 40% below 1990 levels by 2030. Executive Order S-3-05 (2005) establishes a statewide GHG reduction target of 80% below 1990 levels by 2050.

[62] SB 350 (de León) establishes a statewide goal to double California's energy efficiency savings in buildings by 2030.

[63] As approved in D.18-12-015.

[64] As noted in the Opening Testimony of Lindsay Robbins for the Joint Parties, p. 18, "LIWP requires that non-deed-restricted properties sign an affordability covenant in which an owner agrees to ensure that rent levels in at least 66 percent of units will remain at or below the rent affordability standard for at least 10 years." This is the same percentage of units that must be income-qualified in order for the property to be eligible for LIWP.

[65] Cal Advocates-3, pp. 3-4.

customers. Doing so is naturally more costly than serving general market customers, and many of those costs accrue to program administration.

Further, Energy Division staff as well as several of the parties to this proceeding are proposing significant changes to ESA for this and future program cycles. Some aspects of these proposals, notably the robust SPOC with extensive program leveraging, require more administrative resources than a single direct-install program. At the same time, the robust SPOC model with extensive program leveraging achieves deeper energy savings and GHG reductions than ESA is achieving today.

Because the ESA of the future may look substantially different than the ESA of today, it may be more appropriate to consider the question of how to ensure that administrative costs are reasonable as part of the broader question of ESA's future. TURN proposes a reasonable process for making this transition that balances between expediency and thorough consideration.[66]

12. Conclusion

MCE appreciates the opportunity to respond to the observations and recommendations addressed above. Through LIFT, MCE seeks to offer a best-in-class program that meets the diverse needs of affordable housing properties and residents in its service area. MCE looks forward to continuing to deliver energy savings and health, safety and comfort benefits to its customers in the 2021-2026 program cycle.

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[66] Opening Testimony of Alice Napoleon for TURN, p. 53.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

RESPONSE OF THE JOINT CCAS TO JOINT PARTIES' MOTION FOR A COMPREHENSIVE MICROGRID TARIFF DEVELOPMENT PROCESS

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October 15, 2020

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

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RESPONSE OF THE JOINT CCAS TO
JOINT PARTIES' MOTION FOR A COMPREHENSIVE
MICROGRID TARIFF DEVELOPMENT PROCESS

In accordance with the Rule 11.1 of Practice and Procedure of the California Public Utilities Commission ("Commission") the Joint CCAs[1] hereby submit the following response to the Joint Parties'[2] October 1, 2020 *Motion for a Comprehensive Microgrid Tariff Development Process* (the "Motion"). It is critical that the Commission initiate a microgrids tariff development process as soon as possible. The Joint CCAs believe that the tariff development process requested in the Motion is a reasonable, fair, and efficient means of achieving this goal. At the same time, the Joint CCAs believe that the recommended process should be improved through the adoption of a small number of critical clarifications and modifications, discussed below. Subject to these clarifications and modifications, the Joint CCAs strongly support the requested tariff development process and urge the Commission to grant the Motion and initiate the requested workshops as quickly as possible.

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1 The Joint CCAs consist of the following Community Choice Aggregation ("CCA") programs: Peninsula Clean Energy Authority ("PCE"); Sonoma Clean Power Authority ("SCP"); Redwood Coast Energy Authority ("RCEA"); Pioneer Community Energy ("Pioneer"); the California Choice Energy Authority ("CalChoice"); Central Coast Community Energy ("C3E"); San Diego Community Power ("SDCP") ;East Bay Community Energy ("EBCE"); and Marin Clean Energy ("MCE").

2 The Joint Parties consist of Green Power Institute, The Climate Center, Microgrid Resources Coalition, Vote Solar, CEDMC, Clean Coalition, and 350 Bay Area.

I. RESPONSE TO MOTION

The Joint CCAs agree with the Joint Parties that, as part of Track 2 of this Rulemaking and the Commission's implementation of SB 1339, it is critical that the Commission take aggressive steps towards the development of a standardized microgrid tariff (or, more likely, a suite of standardized microgrid tariffs). In Track 2 comments, a wide range of parties, including the Joint CCAs, established that the lack of comprehensive standardized microgrid tariffs is one of the main barriers to the widespread commercialization and implementation of microgrids, and requested that the Commission immediately initiate a general microgrid tariff development process to facilitate the commercialization of microgrids and reduce barriers to microgrid deployment as required by SB 1339.[3]

The Joint CCAs support the Joint Parties' proposed tariff development process. A comprehensive suite of microgrid tariffs as envisioned by SB 1339 will support the deployment of microgrids as a means to increase community resilience by defining the roles and responsibilities of respective parties in the particular project. We share the concerns raised by the Joint Parties that a piecemeal approach to the topic will result in suboptimal outcomes and that time is of the essence. As public agencies that serve our communities "all hands" must be on deck to address the reliability and resilience issues that Californians collectively face. It is simply not enough to rely on the investor-owned utilities to address the broad resilience issues facing our communities. Such an outcome is fundamentally inconsistent with the framework of SB 1339 and will undermine innovation that can lead to cost effective energy solutions. Accordingly, it is imperative that the Commission establish a regulatory process that will guide party efforts to achieve consistent forward movement towards an outcome that will empower all

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

energy consumers to take actions that increase reliability and resiliency. The processes, timelines and structuring of roles and responsibilities of respective parties that can be laid out in a suite of tariffs will create a pathway for all stakeholders to follow in meeting the collective challenge.

The Joint CCAs agree with the Joint Parties that it is unrealistic for the Commission to develop an all-inclusive suite of microgrid tariffs by SB 1339's statutory deadline. As such, the Joint CCAs support the Motion's proposed two-phase approach:[4]

- Phase 1: As part of Track 2 of this Rulemaking, the Commission would hold a series of workshops with the goal of developing a standardized tariff for *simple microgrids* (single-customer or multiple-customer microgrids that have a single interconnection point and do not use IOU infrastructure). This tariff would be implemented by January 2021.
- Phase 2: Prior to Track 3 of this Rulemaking, the Commission would hold a series of workshops to facilitate party understanding of the issues that need to be addressed to develop a comprehensive microgrid tariff (or suite of tariffs) that address all other microgrid types, including microgrids that make use of IOU infrastructure (utility partnership microgrids). The Commission would then address and adopt a comprehensive microgrid tariff/tariffs in Track 3.

The Joint CCAs agree that it is reasonable for the Commission to initially prioritize the development of a tariff for simple microgrids. From a tariff perspective, simple microgrids present a fairly straightforward and discrete set of cost tracking and allocation questions, interconnection and timeline reforms, and other matters. The primary barrier to the widespread deployment of microgrids, Public Utilities Code Section 218, is not relevant to the specific

[4] Motion at 2-3.

question of tariffs for simple microgrids. This is because Section 218 *does not* prohibit multi-parcel/multi-customer microgrids, it merely provides that some multi-parcel/multi-customer microgrids qualify as Commission-regulated public utilities while others do not. While this prospect may not be appealing to microgrid operators, it is completely irrelevant to development of the relevant tariffs. It makes no difference to the IOU whether or not a behind-the-meter microgrid operator is classified as a public utility. While we are intrigued by the ideas raised in the Staff Concept paper for regulatory frameworks that can facilitate microgrids, those ideas can be discussed in subsequent phases of the proceeding after tariffs are developed. As such, we encourage the Commission to move forward with developing simple microgrid tariffs without addressing Section 218.

At the same time, the Joint CCAs believe that the Tariff development process can be significantly improved through the adoption of a few clarifications and improvements. First, the CCAs note that the Motion includes two issues that would be best explored by parties in the workshops:[5]

- Wholesale energy sales – The Motion proposes that the simple microgrid tariff adopted by the Commission permit simple microgrids to make wholesale sales of energy, ancillary services, and capacity as well as sales of grid services to the IOU or the California Independent System Operator ("CAISO"), under any IOU or CAISO tariff for which they can qualify on a performance capability basis.
- Charge exemptions – The Motion proposes that the simple microgrid tariff adopted by the Commission exempt simple microgrids from departing load

[5] Motion at 3.

charges or standby charges, and that the tariff specify the applicability of public benefit charges to power imports by simple microgrids.

The proposals in the motion are a good starting point for workshop discussion, but the development of microgrid tariffs presents matters that require significantly more in-depth consideration to ensure that the full spectrum of legal and policy issues presented in the staff concept paper are adequately addressed and that the tariff is compliant with all statutory and regulatory requirements. At its core, the motion is correct that parties should have a venue and regulatory process that is well structured to allow presentation of tariffs for consideration by the stakeholders in this docket so that their proposals can be vetted, modified as necessary, and then adopted.

The question of whether simple microgrids should be allowed complete participation in the wholesale market raises a range of cost, jurisdictional, market, and compliance questions that should be addressed in workshops. For instance, wholesale market participation may require a deliverability study that may need to be addressed in the tariffs. It is also important to consider whether or how market participation should impact a microgrid's ability to sell excess generation at retail. Workshops should address whether microgrids should have to choose between retail sales or market participation or whether both should be allowed.

The question of whether simple microgrids should be exempt from departing load charges or standby charges also raises a range of issues. For instance, it is unclear whether this proposal extends to the Power Charge Indifference Adjustment. All charges and exemptions should be carefully considered to ensure that, as required by SB 1339,[6] there is no shifting of

[6] Public Utilities Code §§ 8371(b) ("Without shifting costs between ratepayers, develop methods to reduce barriers for microgrid deployment"); 8371(d) ("Without shifting costs between ratepayers, develop separate large electrical corporation rates and tariffs, as necessary, to support microgrids, while ensuring that system, public, and worker safety are given the highest priority.")

costs from microgrid customers to other customers, and no shifting of costs from bundled customers to microgrid customers. In considering the exemptions and cost-shifting, it is critical that microgrids be given full credit for the beneficial attributes that they bring to the IOU grid and other customers, including resilience and avoided transmission and distribution costs.

Finally, while the Joint CCAs agree with the Joint Parties that the purpose of the workshops should be to allow "robust discussion of utility and stakeholder ideas and resolution of issues regarding a comprehensive microgrid tariff that specifies the roles and responsibilities of [IOUs] and community and private microgrid developers in the deployment and operation of microgrids, including compensation rates,"[7] to remove any ambiguity, the Joint CCAs clarify that CCAs, local government entities, and tribal governments can be "community microgrid developers" and should be included and considered in all aspects of the workshop process.

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[7] Motion at 2.

II. CONCLUSION

The Joint CCAs strongly support the Motion, with the modifications and clarifications discussed above. The Motion's phased approach to developing tariffs will allow progress to continue a steady pace, and will allow parties to gain deeper understandings of the issues that underly development of microgrid tariffs. The Motion's proposed tariff development process is the best path forward to developing tariffs that are fair, consistent with statute, practically viable, and consistent with legislative directives to encourage microgrid growth.

Dated: October 15, 2020

Respectfully submitted,

/s/David Peffer

David Peffer
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On Behalf Of:

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

October 16, 2020

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Supplemental Advice Letter 42-E-A

RE: Supplemental: Establish and Implement the Disadvantaged Communities Green Tariff Program Rate and the Community Solar Green Tariff Program Rate

Marin Clean Energy ("MCE") hereby submits this supplemental advice letter ("AL") amending MCE AL 42-E that established and implemented the Disadvantaged Community Green Tariff ("DAC-GT") and the Community Solar Green Tariff ("CS-GT") programs, submitted on May 7, 2020.

TIER DESIGNATION

This supplemental AL has a Tier 3 designation pursuant to OP 17 of D.18-06-027.

EFFECTIVE DATE

Pursuant to General Order 96-B, this Tier 3 AL will become effective when the Commission adopts a resolution approving the advice letter.

BACKGROUND

On June 21, 2018, the California Public Utilities Commission ("Commission" or "CPUC") approved of D.18-06-027, adopting three new programs to promote the installation of renewable generation among residential customers in disadvantaged communities ("DAC"),[1] as directed by the California Legislature in Assembly Bill (AB) 327(Perea), Stats. 2013, ch 611. The three programs include the DAC Single Family Solar Homes ("DAC-SASH") program, which provides up-front incentives for the installation of solar at low-income homes in DACs. The other two programs, the DAC-GT and the CS-GT programs are community solar programs which offer 100% solar energy to customers and provide a 20% discount on the electric portion of the bill.

Pursuant to D.18-06-027, Community Choice Aggregators ("CCAs") may develop their own DAC-GT and CS-GT programs and must file a Tier 3 AL to propose implementation details ("Implementation AL").[2] MCE filed its Implementation AL for the DAC-GT and CS-GT programs

[1] DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen 3.0 as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data.

[2] D.18-06-027, at p.104 (OP 17).

with the Commission in MCE AL 42-E on May 7, 2020.

PURPOSE

MCE submits this Supplemental AL to make two narrowly focused updates to the customer enrollment process under the DAC-GT program. These updates are required due to new Commission guidance since the submission of the original Implementation AL.

1. Updates to the DAC-GT enrollment process due to Green-e certification requirements;
2. Auto-enrollment provisions for eligible customers under the DAC-GT program.

MCE describes the proposed changes in more detail below. Additionally, MCE submits the following updated Appendices (in redline):

1. Appendix A: Implementation Plan for the DAC-GT and CS-GT programs;
2. Appendix B: Schedule DAC-GT, *Disadvantaged Community Green Tariff Program*;
3. Appendix C: Program budgets for program years ("PYs") 2020 and 2021;
4. Appendix D: Marketing, education and outreach ("ME&O") plan for PYs 2020 and 2021;

Updates to the DAC-GT Enrollment Process Due to Green-E Certification Requirements
MCE highlighted in its original Implementation AL that Green-e certification is not feasible for the DAC-GT program under current program rules. In summary, under the proposed customer enrollment process, it cannot be ensured that total customer load under the program does not exceed total generation of all solar resources under the program in any given year. Hence, Green-e Energy certification is not possible for the DAC-GT program and MCE proposed that Green-e certification should not be required as a program element.[3]

In subsequent conversations with the CPUC's Energy Division, MCE learned that Green-e certification must be pursued for any solar project under the DAC-GT and CS-GT programs. Hence, to accommodate for this requirement, MCE proposes to adjust the DAC-GT customer enrollment process to follow the same procedure as for the CS-GT program. Under this methodology, customers subscribe to a portion of the solar resource's output on a monthly basis, thereby preventing the possibility for the aggregated customer load under the program to exceed generation capacity. Under this premise, Green-e certification can be achieved for solar resources under the DAC-GT program. These changes to the DAC-GT customer enrollment rules were incorporated into section 2.1.2. of MCE's updated Implementation Plan (Appendix A) and Schedule DAC-GT (Appendix B).

Auto-Enrollment Provisions for Eligible Customers under the DAC-GT Program
Since the submission of MCE's original Implementation AL, the Commission published Decision (D.) 20-07-008 to implement automatic enrollment of certain eligible customers under PG&E's

[3] MCE AL 42-E, Appendix A, at 10.

DAC-GT program.[4] While the Decision does not explicitly direct CCAs to also implement automatic enrollment provisions under their DAC-GT programs, MCE believes that it is appropriate to do so in furtherance of the Commission's goals to reduce the cost burden on some of the most vulnerable customers.

Therefore, MCE will automatically enroll any eligible customers that live in one of the top 10% of DAC census tracts statewide that are located in MCE's service area until customer subscriptions reach MCE's DAC-GT program cap. Priority will be given to customers who have made an effort to pay, as defined by at least 4 full or partial payments in the last 8 months ("category 1"). If program capacity remains unsubscribed after enrolling these customers, MCE will enroll additional customers in the following order:

1. Customers who have made at least 3 full or partial payments in the past 8 months ("category 2")
2. Customers who have made at least 2 full or partial payments in the past 8 months ("category 3")[5]

If there is not enough program capacity to enroll all customers in a given category under the DAC-GT program, customers from the respective category will be randomly selected for program enrollment. All remaining customers will be placed on a waitlist. MCE will monitor program attrition on a monthly basis and will enroll additional customers from the waitlist as program capacity becomes available.

MCE makes the appropriate updates in section 2.1 and 6 of MCE's updated Implementation Plan (Appendix A), as well as in Schedule DAC-GT (Appendix B). To accommodate for this new auto-enrollment provision, MCE also adjusts its marketing, education and outreach ("ME&O") plan and budget under the DAC-GT program. More details are provided in the updated program budget (Appendix C) and ME&O plan (Appendix D).

CONCLUSION

MCE respectfully requests the Commission approve the modified implementation details and budgets proposed by MCE in this supplemental AL.

NOTICE

A copy of this AL is being served on the official Commission service lists for Rulemaking R.14-07-002. For changes to this service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

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[4] D.20-07-008, *Decision Implementing Automatic Enrollment of Disadvantaged Communities Green Tariff*, from July 23, 2020.

[5] MCE is expecting to serve approximately 1,762 customers under the DAC-GT program, based on the program cap of 4.31MW (assuming a 28% capacity factor of the solar project and an average customer usage of 500 kWh per month). Based on data through August 2020, 1411 customers in the top 10% DACs have made at least 4 payments in the past 8 months, 1604 customers have made at least 3 payments in the past 8 months and 1748 customers have made at least 2 payments in the past 8 months.

PROTESTS

MCE respectfully requests that the Commission maintain the original protest period designated in MCE AL 42-E pursuant to GO 96-B, General Rule 7.5.1, and not reopen the protest period.

CORRESPONDENCE

For questions, please contact Jana Kopyciok-Lande at (415) 464-6044 or by electronic mail at jkopyciok-lande@mceCleanEnergy.org.

/s/ Jana Kopyciok-Lande

Jana Kopyciok-Lande
Senior Policy Analyst
MARIN CLEAN ENERGY

cc: Service List: R.14-07-002

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Jana Kopyciok-Lande
Phone #: 415-464-6044
E-mail: jkopyciok-lande@mcecleanenergy.org
E-mail Disposition Notice to: jkopyciok-lande@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE

ELC = Electric   GAS = Gas   WATER = Water
PLC = Pipeline   HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 45

Tier Designation: 2

Subject of AL: Marin Clean Energy's 2021 Energy Efficiency Annual Budget Advice Letter

Keywords (choose from CPUC listing): Energy Efficiency, Compliance

AL Type: [ ] Monthly [ ] Quarterly [x] Annual [ ] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.15-10-028 and D.18-05-041

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information: N/A
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information: N/A

Resolution required? [ ] Yes [x] No

Requested effective date:

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1] Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Name: Jana Kopyciok-Lande
Title: Senior Policy Analyst
Utility Name: Marin Clean Energy
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Name: Alice Havenar-Daughton
Title: Director of Customer Programs
Utility Name: Marin Clean Energy
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Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

Implementation Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs

Proposed by Marin Clean Energy

~~Alice Havenar-Daughton~~Heather Shepard
Director of ~~Customer Programs~~Public Affairs
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October 16, 2020

TABLE OF CONTENTS

1. INTRODUCTION

In June 2018, the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 18-06-027, creating three new programs to promote the installation of renewable generation among residential customers in disadvantaged communities (DACs). The three programs include the DAC Single Family Solar Homes (DAC-SASH) program, which provides up-front incentives for the installation of solar at low-income homes in DACs. The other two programs, the DAC Green Tariff (DAC-GT) and the Community Solar Green Tariff (CS-GT) programs are community solar programs which offer 100% solar energy to customers and provide a 20% discount on the electric portion of the bill.

The DAC-GT program is available for residential customers who live in DACs and meet the income eligibility requirements for the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs. The CS-GT program is structured similarly to the DAC-GT program but is intended to drive more local, community-developed solar projects. The CS-GT program requires community involvement with the solar project through a local sponsor and will result in a solar facility serving a nearby community. The CS-GT program is open to all residential customers located in a DAC, with at least 50% of the program's capacity reserved for CARE and FERA eligible customers.

Both programs are funded first through greenhouse gas (GHG) allowance proceeds. If such funds are exhausted, the programs will then be funded through public purpose program (PPP) funds.

Pursuant to D.18-06-027, Community Choice Aggregators (CCAs) may develop and implement their own DAC-GT and CS-GT programs in addition to the IOU's programs. Resolution E-4999 allocated a portion of the program capacity to CCAs and determined that any CCA interested in running the programs must file an Implementation Advice Letter (AL) with the CPUC by 1/1/2021.

MCE herby submits the Implementation Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs (Implementation Plan), detailing the rules and requirements for the two programs. More specifically, the Implementation Plan contains the following sections:

- Customer eligibility and enrollment
- Rate and discount design
- Procurement
- Budget and cost recovery
- Marketing, education, and outreach
- Reporting
- Program measurement and evaluation

2. CUSTOMER ELIGIBILITY AND ENROLLMENT

This section establishes customer and sponsor eligibility and enrollment terms. These terms can also be found in the DAC-GT and CS-GT tariff schedules.

2.1. DAC-GT Program

2.1.1. Customer Eligibility

The DAC-GT program is available to residential customers who live in DACs, receive generation service from MCE, and meet the income eligibility requirements for the CARE program and/or the FERA program.[1]

DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen 3.0 tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data.[2] In the event that the CalEnviroScreen tool is updated, and MCE has unsubscribed program capacity available, MCE will file a Tier 1 Advice Letter within 30 days of the release of the new version to update program eligibility rules. Customers who are already enrolled in DAC-GT will retain their eligibility even if their census tract is no longer considered a top 25 percent DAC under the revised CalEnviroScreen.

Eligibility of customers is verified at the level of the Service Agreement ID (SA ID). Service accounts enrolled under the following programs and services are ineligible to participate in the DAC-GT program:

- IOU bundled service;
- Direct access customers;
- Standby service;
- Net energy metering (NEM) rates;
- Non-metered service;
- Rates that are not CARE- or FERA-eligible;
- Non-residential rates;

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[1] Customers must be eligible to participate in either the CARE or FERA programs; they are not required to be enrolled under those programs to be eligible to participate in DAC-GT. CARE/FERA eligibility is established as currently defined under those programs.

[2] D.18-06-027, *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*, at p.16 and p.53.

- Master-metered customers;[3]
- Schedule CS-GT, Community Solar Green Tariff.

2.1.2. Customer Enrollment

Enrollment of customers under Schedule DAC-GT occurs at the level of the SA ID. Subscribing customers have their electricity met with 100% solar energy based on their actual usage each month and will receive a 20% discount on their otherwise applicable tariff for the enrolled SA IDs. Customer enrollment is capped at a maximum of 2 MW solar equivalent per SA ID.[4]

~~Customers interested in enrolling in the DAC-GT program can sign up with MCE online, by phone, or with a hardcopy application. MCE will verify customer eligibility based on service account address (to verify DAC census tract) and CARE/FERA enrollment status. If a customer is not currently enrolled in the CARE or FERA programs, they will be encouraged to enroll in the CARE/FERA programs through the existing IOU enrollment process. MCE will support the customer as needed in the CARE/FERA application process with the utility. Once a customer's CARE/FERA eligibility has been established, MCE will enroll the customer under the DAC-GT program.~~The DAC-GT program allows eligible customers to purchase renewable electricity produced by a pool of community solar projects for up to 100% of their electric usage. More specifically, customers subscribe to a percentage of the total program's capacity based on their previous 12-month average monthly usage.[5] The following example describes the calculation of the customer's subscription allocation in more detail: We assume for this example that a residential customer has an average historical usage based on the previous 12-months of 500 kWh per month. The total program capacity is 4.31MW which produce approximately 944 MWh of solar power per month.[6] The customer's subscription allocation is then calculated as a percentage of the average monthly output of the solar system (500 kWh/ 944,000 kWh = 0.00053% of monthly output of the pool of solar projects). In this example, the customer will subscribe to 0.00053% of the total capacity under the DAC-GT program. This percentage allocation is set at the time of customer subscription but may

[3] MCE cannot ensure that all tenants under one master-meter are eligible for the CARE or FERA program, as the sub-metered tenants are not MCE direct customers. Hence, master-metered accounts are not eligible for the DAC-GT program.

[4] This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

[5] If previous 12-month historical usage is not available, the average monthly usage will be derived from as many months as available. For customers establishing new service, the class average monthly usage will be used.

[6] Based on a capacity factor of 30%.

be revisited periodically to ensure accurate allocations of project capacity. The program is fully subscribed once program enrollment meets 100% of total capacity under the program.

MCE will automatically enroll any eligible customers that live in one of the top 10% of DAC census tracts statewide that are located in MCE's service area until customer subscriptions reach MCE's DAC-GT program cap. Priority will be given to customers who have made an effort to pay, as defined by at least 4 full or partial payments in the last 8 months (category 1). If program capacity remains unsubscribed after enrolling these customers, MCE will enroll additional customers in the following order:

- Customers who have made at least 3 full or partial payments in the past 8 months (category 2);
- Customers who have made at least 2 full or partial payments in the past 8 months (category 3).[7]

If there is not enough program capacity to enroll all customers in a given category under the DAC-GT program, customers from the respective category will be randomly selected for program enrollment. All remaining customers will be place on a waitlist. MCE will monitor program attrition on a monthly basis and enroll additional customers from the waitlist as program capacity becomes available.

Customer enrollment will be available immediately upon program launch. A participating customer can remain on the DAC-GT tariff for up to 20 years from the time of enrollment. There is no contract required when enrolling in the DAC-GT program. Customers may ~~enroll~~remain enrolled for any number of months, and there is no enrollment or cancellation fee. Customers may choose to cancel participation in the program at any point in time. Cancellation of a customer's participation will become effective on the next meter read date; cancellations made within five (5) business days of the next meter read date may not be changed for an additional billing cycle. Customers who, after enrollment into the DAC-GT Program, become ineligible for CARE or FERA will be un-enrolled from the DAC-GT program.

The customer will be placed on the DAC-GT rate on the first day of the next billing cycle where the billing cycle start date occurs at least five (5) business days after the date of the customer's request. A customer request that is received within five (5) business days of the customer's next billing cycle may result in the customer being placed on the DAC-GT rate in the following billing cycle.

~~Eligible customers may enroll in the program until customer subscriptions reach 4.31 MW (MCE's DAC-GT program cap). Once MCE reaches its program cap, a waitlist will be maintained for new subscriptions. When program capacity becomes available, MCE will enroll new eligible customers on a first-come, first-served basis up to the program cap.~~

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[7] MCE is expecting to serve approximately 1,762 customers under the DAC-GT program, based on the program cap of 4.31MW (assuming a 28% capacity factor of the solar project and an average customer usage of 500 kWh per month). Based on data through August 2020, 1411 customers in the top 10% DACs have made at least 4 payments in the past 8 months, 1604 customers have made at least 3 payments in the past 8 months and 1748 customers have made at least 2 payments in the past 8 months..

A customer's service under this schedule is portable within MCE electric service area as long as the customer continues to live in a DAC as defined under the program and continues to meet all other eligibility requirements. If the customer is found to still be eligible, MCE retains their status as a program participant and does not require the customer to go on a waitlist, as long as the customer's turn-on date at the new location is within 90 days of their final billing date at their original location.

2.2. CS-GT Program

2.2.1. Customer Eligibility

The CS-GT program is available to residential customers who live in DACs (as defined above)[8] and receive generation service from MCE. Non-residential customers are not eligible to participate, except for the project sponsor (see more information on sponsor eligibility rules below). A solar generation project supporting the program must be located within five miles of the participating customers' census tract.[9] At least fifty percent of a project's capacity must be reserved for low-income customers, defined as those meeting the income qualifications for either the CARE or FERA programs.[10]

Eligibility of customers is verified at the level of the SA ID. Service accounts enrolled under the following programs and services are ineligible to participate in the CS-GT program:

- IOU bundled service;
- Direct access customers;
- Standby service;
- Net energy metering (NEM) rate;
- Non-metered service;
- Schedule DAC-GT, Disadvantaged Communities Green Tariff.

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[8] Customers who live in the San Joaquin Valley (SJV) pilot program communities (as defined in R.15-03-010) are also eligible for the program even if their community is not among the top 25% DACs as defined by CalEnviroScreen. Currently, there are no CCAs in existence in the SJV pilot communities. However, if the SJV pilot communities expand, an existing CCA expands or a new CCA is created, those customers would also be eligible for the CCA CS-GT program.

[9] Per D.18-12-015, *Decision Approving San Joaquin Valley Disadvantaged Communities Pilot Projects*, CS-GT projects in SJV pilot communities can be located within a 40-mile radius of the pilot communities they serve. As discussed above, there are currently no CCAs in existence in SJV pilot communities. However, if this changes, these locational requirements would also apply to CCA CS-GT programs.

[10] As under the DAC-GT program, customers do not need to be currently enrolled under CARE/FERA to be eligible for the CS-GT program. However, they will be encouraged to enroll under the CARE or FERA program through the existing IOU enrollment process when enrolling under the CS-GT program.

Master-metered customers may participate in the CS-GT program so long as they enroll all of their usage under the master-metered account in the program. Individual tenants of a master-meter customer are not eligible to participate on an individual basis. Master-metered customers must also meet all other eligibility requirements.

In the event that CalEnviroScreen is updated, MCE will file a Tier 1 AL within 30 days of the release of the new version to update program eligibility rules. As with the DAC-GT program, all customers in an eligible DAC at the time of a project's initial energy delivery date will remain eligible to subscribe to that CS-GT project, even if their DAC designation changes in subsequent iterations of CalEnviroScreen. This grandfathered eligibility will apply to both existing subscribers and customers not previously subscribed to the project in that same DAC, to ensure that the project's output can be fully subscribed by customers whose census tract is within 5-miles of the project.

2.2.2. Customer Enrollment

As with DAC-GT, enrollment of customers occurs at the level of the SA ID. Customer enrollment is capped at a maximum of 2 MW solar equivalent per SA ID.[11]

The CS-GT program allows eligible customers to purchase renewable electricity produced by a local community solar project for up to 100% of their electric usage. More specifically, customers subscribe to a percentage of the solar system's project capacity based on their previous 12-month average monthly usage.[12] As described below, participating customers will receive a 20% discount on their otherwise applicable tariff for enrolled SA IDs. Customers cannot be subscribed to more than one CS facility at any time.

The following example describes the calculation of the customer's subscription allocation in more detail: We assume for this example that a residential customer has an average historical usage based on the previous 12-months of 500 kWh per month. The customer subscribes to a 100 kW community solar project with an estimated average monthly output of 21,900 kWh.[13] The customer's subscription allocation is then calculated as a percentage of the average monthly output of the solar system (500 kWh/ 21,900 kWh = 2.3% of monthly output). In this example, the customer will subscribe to 2.3% of the project's capacity (or 2.3kW of the 100kW system). This

[11] This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

[12] If previous 12-month historical usage is not available, the average monthly usage will be derived from as many months as available. For customers establishing new service, the class average monthly usage will be used.

[13] Based on a capacity factor of 30%.

percentage allocation is set at the time of customer subscription but may be revisited periodically to ensure accurate allocations of project capacity.

Customers interested in enrolling in the CS-GT program can sign up with MCE online, by phone, or with a hardcopy application. MCE will verify customer eligibility based on service account address to verify DAC census tract and 5-mile locational requirement. CARE/FERA enrollment status will also be identified to track subscription of low-income customers. Enrollment of new customers is available until 100% of project capacity is subscribed. Enrollment attrition will be reviewed on a monthly basis, and the program will be available for new enrollments until the project is fully subscribed.

Low-income customers will be enrolled on a first-come, first-served basis. Once 50 percent of project capacity is subscribed by low-income customers, non-low-income qualified customers located in DACs will become eligible for enrollment. These customers can be recruited before the 50 percent subscription requirement for low-income customers is met. However, they will be placed on a waitlist until 50 percent of the project capacity is subscribed by low-income customers.

MCE will assess the subscription rate of low-income customers on a monthly basis after the Power Purchase Agreement (PPA) is awarded. If the low-income subscription rate drops below 50 percent over the life of the project, existing non-low-income customers are not required to go back on a waitlist. However, new enrollments of non-low-income program participants will be barred until the 50 percent low-income threshold is met again. During this time, new enrollments of non-low-income participants will be put on a waitlist. MCE will inform the Commission's Energy Division Director in writing if the low-income enrollment rate drops below 35 percent of project capacity.

The customer will be placed on the CS-GT rate on the first day of the next billing cycle where the billing cycle start date occurs at least five (5) business days after the date of the customer's request. A customer request that is received within five (5) business days of the customer's next billing cycle may result in the customer being placed on the CS-GT rate in the following billing cycle.

Customer enrollment will be available immediately upon program launch. There is no contract required when enrolling for the CS-GT program. Customers may enroll for any number of months, and there is no enrollment or cancellation fee. Cancellation of a customer's participation will become effective on the next meter read date; cancellations made within five (5) business days of the next meter read date may not be changed for an additional billing cycle. A participating customer can remain on the CS-GT tariff for the duration of the project's contract term, or up to 20 years, whichever is less. Customer participation in the program automatically terminates should the PPA between MCE and the developer for the CS-GT facility to which the customer is subscribed be terminated or the delivery term ends.

A customer's service under this schedule is portable within MCE electric service area as long as the customer continues to live in a DAC as defined under the program and continues to meet all other eligibility requirements (including the locational requirement). If the customer is found to still be eligible, MCE will retain their status as a program participant and will not require the customer to go on a waitlist, as long as the customer's turn-on date at the new location is within 90 days of their final billing date at their original location.

2.2.3. Sponsor Eligibility

Under the CS-GT program, community involvement must be demonstrated by a non-profit community-based organization (CBO) or a local government entity "sponsoring" a community solar project on behalf of residents. Local government entities include schools. The sponsor's role is to work with the project developer to encourage program participation in the community. Sponsors are also required to include job training and workforce development in their efforts to benefit the local communities which would benefit from their projects. Additional sponsor requirements are described in the Procurement section below.

To receive the 20% discount on eligible as described below, the sponsor must fulfill the following requirements:

1. The sponsor must be an MCE electric customer;
2. The sponsor must take service on the Community Solar Green Tariff;
3. The sponsor must be located in the same geographic areas as any other customer, i.e., within a disadvantaged community with the solar project being located 5 miles from the sponsor's census tract;
4. Fifty percent of the project's capacity must be subscribed by low-income customers; and
5. The sponsor must meet all other eligibility requirements of any participating customer as described in the section on CS-GT customer eligibility above.

CBOs or local government entities that do not fulfill all or any of these requirements may still become project sponsors; however, they are not eligible to receive the 20 percent discount.

There may be more than one sponsoring entity supporting a single community solar project. Multiple sponsors may share the 20 percent discount as long as all sponsors meet the eligibility requirements outlined above.

A sponsor may also be (although is not required to be) a site host.[14]

2.2.4. Sponsor Enrollment

Sponsors of a CS-GT project are subject to the same enrollment rules and requirements as described above for residential customers participating in the program. For example, enrollment occurs at the level of the SA ID and is capped at a maximum of 2MW of solar equivalent per SA

[14] For the purposes of this program, the concept of a "host" only refers to a customer site where the project is located. The community solar project must be located in-front-of-the meter, even if located at a customer host site. Accordingly, all concepts and rules of an in-front-of-the-meter program continue to apply.

ID.[15]

The sponsor's subscription allocation is also calculated the same way as for any other participating customer with one modification. A sponsor's subscription allocation is limited to a maximum of 25 percent of the project's energy output (not to exceed the sponsor's energy needs).

To illustrate this in more detail, we use the same example as before (100kW solar project with a monthly output of 21,900 kWh). We assume now that the total monthly usage among all the sponsor's eligible SA IDs is 10,000 kWh, which is larger than 25% of monthly project output (5,475 kWh). In this example, the sponsor's subscription allocation is limited to 25% of project output per month, and the sponsor will receive the discount on only 5,475 kWh.

If two or more sponsors are designated, the sponsors will need to inform MCE in writing of how the "discountable usage" (in this example, 5,475 kWh/monthly) are to be allocated between them.

3. RATE AND DISCOUNT DESIGN

This section describes the rules and requirements for providing the 20 percent bill discount to participating customers.

3.1. Customer Bill Discount

Participants in both the DAC-GT and CS-GT programs will receive a 20% discount on the electric portion of the bill compared to their otherwise applicable rates (OAR).[16] The discount applies as long as customers are enrolled under the programs and they comply with all the eligibility and enrollment terms described in MCE's DAC-GT and CS-GT tariff sheets.

For low-income customers enrolled in the CARE or FERA programs, the OAR is the customer's existing CARE or FERA rate.[17] Accordingly, the 20% discount for these customers will be applied to low-income customer bills after the CARE/FERA discount has been applied.

For customers who are not enrolled in CARE or FERA programs, the OAR is the customer's existing rate schedule before program enrollment. Residential customer SA IDs that are already enrolled in MCE's 100% renewable energy generation service option (i.e., MCE's "Deep Green"

[15] This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

[16] D.18-06-027 at p.53 and p.74.

[17] Resolution E-4999, Conclusion 28 at p.55.

rate) when enrolling under the programs, will be defaulted to MCE's base rate (i.e., MCE's "Light Green" rate) for the purposes of calculating the 20% discount. In other words, MCE's Light Green rate becomes the de-facto OAR for residential customers who are not on the CARE or FERA rate.

A customer's electric portion of the bill consists of two main parts: (1) generation portion, and (2) delivery portion. CCAs, as the generation service provider, only have timely access to customers' generation charges, and therefore will only calculate the 20% discount for the generation portion of the electric bill. The respective utility (in MCE's case PG&E) will be responsible for calculating the 20% discount of the delivery portion of the bill for CCA program participants.

More specifically, MCE proposes the following monthly discount calculation and billing procedures for MCE program participants:

1. PG&E sends MCE customer usage information;
2. MCE calculates the 20% discount of the generation portion of the electric bill;
3. PG&E applies the CARE/ FERA discount and then calculates the 20% discount of the delivery portion of the electric bill;
4. MCE sends PG&E generation charges (reduced by 20% bill discount) for inclusion on the bill;
5. PG&E compiles the bill, sends it to customer, and gets paid by the customer;
6. PG&E pays MCE the generation charges (reduced by 20% bill discount) per established processes;
7. MCE recovers the revenue shortfall for providing the discount on the generation portion of the bill through the program's cost recovery mechanisms (see details below);
8. PG&E recovers the revenue shortfall for providing the discount on the delivery portion of the bill through the program's cost recovery mechanisms.

In regards to bill presentment, the 20% bill discount on the generation portion of the bill will be shown on the MCE portion of the bill; the 20% discount on the delivery portion of the bill is displayed on the PG&E portion of the bill.

3.2. Sponsor Bill Discount

CS-GT project sponsors who meet all of the eligibility requirements outlined above receive a 20% bill discount on enrolled SA IDs. The sponsor bill discount will be calculated based on the same methodology as described above for residential program participants with one modification. The sponsor bill discount is only applied to a sponsor's subscription allocation, i.e., limited to a maximum of 25% of the project's energy output (not to exceed the sponsor's energy needs under the enrolled SA IDs). The discount applies as long as sponsors are enrolled under the programs and they comply with all the sponsor eligibility and enrollment terms described above. If two or more sponsors are designated, both sponsors must inform MCE in writing of how the "discountable usage", capped at 25% of the project's energy output, are to be allocated among them. MCE will then calculate the applicable discount to each sponsor accordingly.

The sponsor's discount is available to sponsors only after the community solar project has reached its required minimum 50% low-income subscription rate. If the subscription rate of low-income customers drops under 50% of project capacity at any time throughout the life of the project, the sponsor bill credit will not be revoked.

4. PROCUREMENT

Per Resolution E-4999, MCE has been allocated 4.31 MW for its DAC-GT program and 1.11 MW for its CS-GT program based on the proportional share of residential customers in DACs that MCE serves.[18]

Resolution E-4999 also allows CCAs that serve customers in the same IOU service territory to share and/or trade program capacity.[19] MCE is not trading/ sharing capacity under either program at this point in time but reserves the right to do so before 1/1/2021 through a supplemental Advice Letter filing.

All renewable energy resources procured on behalf of customers participating in the DAC-GT and CS-GT programs, as well as interim resources, will comply with the California Air Resources Board's (CARB) Voluntary Renewable Electricity Program. California-eligible GHG allowances associated with these purchases will be retired on behalf of participating customers as part of CARB's Voluntary Renewable Electricity Program.

It is MCE's understanding that Green-e certification is not be feasible for the DAC-GT program under current program rules. Per D.18-06-027, 100% of a customer's annual usage is covered with solar energy under the program. Subscription to the program is based on a customer's historical usage quantities and once subscribed, no annual true-up mechanism between the sum of participating customer's total annual usage and total annual generation of all resources under the DAC-GT program will occur. It could be the case that in any given year, total customer load under the program exceeds total generation of all resources under the program. In MCE's understanding, the Green-e Energy Code of Conduct does not allow for this to happen. Hence, MCE proposes that Green-e certification is not required as a program element.

4.1. DAC-GT Program

DAC-GT projects must be located in a DAC within the same IOU service territory as the customers being served. DAC-GT projects located in census tracts that were previously considered a DAC

[18] Resolution E-4999, Table 1 at p.14. Due to the continued growth and expansion of CCAs, MCE recommends that the Commission review CCA capacity allocations biennially and adjust the allocation of remaining program capacity in each IOU's distribution service territory proportional to the then current share of residential customers in DACs. The first capacity allocation adjustment should occur by January 1, 2022 and every two years thereafter.

[19] Resolution E-4999 at p.54, Findings and Conclusions ¶ 17.

under the program, but are no longer scored as such due to updates to the CalEnviroScreen tool, will continue to be eligible to serve customers under the DAC-GT program.[20]

MCE was assigned a capacity allocation of 4.31 MW for the DAC-GT program. Eligible projects must be sized between 500 kW and 20 MW (4.31 MW in MCE service area due to the program cap). MCE will consider both full deliverability and energy-only projects in the solicitations.

MCE will issue DAC-GT solicitations once a year until the program cap is reached. The solicitation process will follow these guiding principles:

1. The project is selected through a competitive solicitation;
2. MCE executes a Power Purchase Agreement (PPA) with a developer for a solar project;
3. There is no direct relationship between the customer and the project developer;
4. Subscribing customers receive 100% renewable energy; and
5. Subscribing customers receive a defined bill credit.

Eligibility for procurement under the DAC-GT program requires that bid pricing must be at or below the statewide CCA cost cap provided to CCAs by the CPUC's Energy Division Staff via email on September 5, 2019.[21]

MCE will serve DAC-GT customers on an interim basis until the new DAC-GT resources come online utilizing existing resources that meet all of the requirements of the DAC-GT program. MCE proposes to use the following solar resource under MCE's portfolio as interim resources for the DAC-GT program:[22]

- Cottonwood Solar Project (Goose Lake facility)
- Address: 15004 Corocan Rd., Lost Hills, CA 93249
- Nameplate capacity: 12 MW
- Commercial Online Date: 2015

Once the new DAC-GT solar resources come online, MCE DAC-GT customers will be transferred

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[20] In the event that the CalEnviroScreen tool is updated, MCE will file a Tier 1 Advice Letter within 30 days of the release of the new version to update program eligibility rules.

[21] Energy Division staff explains in the email from September 5, 2019 that CCAs are expected to compare the unadjusted project bids to the price cap. In other words, CCAs should use the price cap to screen the submitted bid prices before making adjustments to those prices such as time of delivery adjustments. Energy Division staff also clarified in a workshop that the value of the CCA cost cap will change when all three IOUs procure new resources under the Green Tariff Shared Renewables (GTSR) program or under the Renewable Auction Mechanism (RAM) as-available-peaking category. Energy Division will notify the CCAs when this occurs.

[22] The solar resource is located in a DAC within PG&E's distribution service territory and is currently under contract with MCE.

to these projects.

4.2. CS-GT Program

CS-GT projects must be sited in a DAC within the same IOU service territory as the customers being served and must also be located within 5 miles of the benefitting customers' DAC census tract. CS-GT projects located in census tracts that were previously considered a DAC under the program, but are no longer scored as such due to updates to the CalEnviroScreen tool, will continue to be eligible to serve customers under the CS-GT program. [23]

MCE was assigned a capacity allocation of 1.11 MW in Resolution E-4999 for the CS-GT program.[24] Eligible projects have no minimum size and a maximum size of 3 MW (1.11 MW in MCE service area due to the program cap). MCE will consider both full deliverability and energy-only projects in the solicitations.

MCE will issue CS-GT solicitations once a year until the program cap is reached. Solicitations will be run in conjunction with the DAC-GT program's solicitations. However, the DAC-GT and CS-GT program will each have separate capacity allocations and bid requirements under the same solicitation. The solicitation process will follow the same guiding principles as for the DAC-GT program:

- The project is selected through a competitive solicitation;
- MCE executes a Power Purchase Agreement ("PPA") with a developer for a solar project;
- There is no direct relationship between the customer and the project developer;
- Subscribing customers receive up to 100% renewable energy; and
- Subscribing customers receive a defined bill credit.

Eligibility for procurement under the DAC-GT program requires that bid pricing must be at or below the statewide CCA cost cap provided to CCAs by the CPUC's Energy Division Staff via email on September 5, 2019.[25]

Twenty-five percent of each project's capacity must be subscribed by eligible low-income customers prior to permission to operate (PTO). If this requirement is not met, the project will not

[23] In the event that the CalEnviroScreen tool is updated, MCE will file a Tier 1 Advice Letter within 30 days of the release of the new version to update program eligibility rules.

[24] Resolution E-4999, Table 2 at p.14

[25] Energy Division staff clarifies in its September 5, 2019, email that CCAs are expected to compare the unadjusted CS-GT project bids to the price cap. In other words, CCAs should use the price cap to screen the submitted bid prices before making adjustments to those prices such as time of delivery adjustments.

be able to begin delivery under the contract.[26]

Community sponsorship of the project by a CBO or local government is required to be eligible to bid for the CS-GT program. Developers will be required to obtain and provide a letter of commitment from a sponsor as part of the solicitation process. A letter of commitment from a sponsor must include:

1. Demonstration of substantial interest of community members in subscribing to the project;
2. Estimated number of subscribers, with justification to ensure project is sized to likely demand;
3. A preliminary plan to conduct outreach and recruit subscribers (which may be conducted in conjunction with the developer and/or MCE); and
4. Siting preferences, including community-suggested host sites, and verification that the site chosen for the bid is consistent with community preference.

In addition to these solicitation requirements, D.18-06-07 also established several metrics for prioritization of CS-GT project bids.[27] First, MCE will prioritize projects located in the top 5% census tracts of disadvantaged communities per CalEnviroScreen 3.0 (if applicable). Second, MCE will grant priority for projects that leverage other government funding such as a state Community Services Department (CSD) grants, or projects that provide evidence of support or endorsements from programs such as Transformative Climate Communities or other local climate initiatives. Third, MCE will also prioritize job training and workforce development factors and will require workforce development for all projects, including local hiring and targeted hiring, to enable creation of job opportunities for low-income communities.

To encourage the development of CS-GT projects, MCE will provide support to local CBOs and project developers to identify potential community solar sites within its service territory as needed. As a local government agency, MCE has existing relationships within its communities that can be leveraged to enhance the success of the CS-GT program.

5. BUDGET AND COST RECOVERY

This section describes the rules and requirements regarding program costs and budget, funding and cost recovery mechanisms, and the process of reviewing program costs.

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[26] No interconnection or other project development processes will be influenced. The project can be finalized but payment on the delivery will not be started until 25% low-income customer subscription is achieved.

[27] D. 18-06-027 at p. 82ff

5.1. Budget

Program Administrators must submit annual program budget forecasts via a Tier 1 Advice Letter by February 1st of every year for the following program year. Each Advice Letter must include separate program budget forecasts for the DAC-GT and CS-GT programs and must clearly identify any costs that are shared between the programs.

Annual budget submissions will include, at a minimum, the following budget line items:

1. Generation cost delta, if any;[28]
2. 20 percent bill discount for participating customers;
3. Program administration costs;
4. Marketing, education and outreach (ME&O) costs; and
5. Program evaluation costs.

Generation Cost Delta

For subscribed energy, the generation cost delta is the net value of renewable resource costs and other generation-related costs used to support the program that are more or less than the resource and other generation-related costs for the typical residential rate.

MCE will calculate the generation cost delta by comparing the sum of energy contract prices, incremental Resource Adequacy (RA), and incremental shaping costs for DAC-GT and CS-GT resources with the rate for MCE's Light Green Basic Residential[29] service. The cost components are defined as follows:

- The **energy generation cost** for the DAC-GT program will be the weighted average of the energy contract prices of all solar projects under the program;
- The **energy generation cost** for the CS-GT program will be the weighted average of the specific solar project that the customer subscribes to;
- The incremental **RA value or cost** of DAC-GT and CS-GT resources are determined by CAISO Net Qualifying Capacity multiplied by 2020 RA value benchmarks, compared against the RA cost as determined by PG&E residential load profile multiplied by the 2020 RA value benchmarks;

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[28] Resolution E-4999 establishes that *above market* generation costs should include net renewable resource costs in excess of the otherwise applicable class average generation rate that will be used to calculate the customers' bills. In conversations with the CPUC's Energy Division after the release of the Resolution, it was clarified that this budget line item is intended to cover both a potential higher, as well as lower, cost of the DAC-GT/ CS-GT resources than the otherwise applicable class average generation rate. Hence, the term is updated to state the "*Delta of generation costs* between the DAC-GT/ CS-GT resources and the otherwise applicable class average generation rate".

[29] Equivalent to PG&E's tiered E-1 rate. This rate currently serves approximately 90% of MCE residential accounts.

- The incremental **shaping value or cost** of DAC-GT and CS-GT resources as determined by the applicable resources' production profile multiplied by 2019 (updated annually) CAISO Day-Ahead LMP for PG&E DLAP, compared against the PG&E residential load profile multiplied by the 2019 CAISO Day-Ahead LMP for PG&E DLAP.

The delta between the base rate and the total generation cost of the DAC-GT or CS-GT resource will then be multiplied by the volume served each month by each program to arrive at the total above-market generation cost or below-market generation savings from the program.

The above/below market generation costs, if any, will not be charged to participating customers and thus will not appear on the customers' bills. Instead, the cost delta, if any, will be tracked in the background and will be charged as program costs (or credits) and recovered through GHG allowance revenue and PPP funds as outlined below.

Because new DAC-GT/ CS-GT facilities will be contracted to MCE to provide all of their output, any potential above-market costs associated with unsubscribed output will also be covered by program funds.[30] MCE will seek to sell excess energy not used by program participants to the market and any revenue received will be applied as a credit towards program funds. In preparation of the annual budget advice letter, MCE will true up the full costs for unsubscribed generation under the programs against any revenue received and will charge the remainder to the programs as a separate budget line item.

Participant Bill Discount

As described above, program participants will receive a 20-percent discount on the otherwise applicable rate of eligible SA IDs. MCE's annual program budget will include the estimated total amount of revenue loss to be experienced by providing the 20% discount on the generation portion of the bill. More specifically, this calculation will be based on forecasted monthly enrollment in each program and average monthly bills by customer class.

Program Administration and ME&O Costs

Under the DAC-GT and CS-GT programs, program administrators (PAs) can recover all program administration and ME&O costs from program funds. MCE will track program costs for the DAC-GT and CS-GT programs in separate accounts.

Administrative budget must be broken out into:

1. Program management;
2. Information technology (IT);
3. Billing operations;
4. Regulatory compliance; and

[30] D.18-06-027 at p. 83.

5. Procurement.

Marketing, education and outreach (ME&O) costs must be broken out in:

1. Labor costs;
2. Outreach and material costs;
3. Local CBO/ sponsor costs (for CS-GT only).

Resolution E-4999 establishes a budget cap of 10% of the total budget for program administration costs and a budget cap of 4% of the total budget for ME&O costs.[31] However, administrative and ME&O costs may be higher than these budget allocations in the first two years of program implementation, acknowledging that program start-up costs may be higher.

Program Evaluation Costs

The DAC-GT and CS-GT programs must be reviewed by an independent evaluator every three years. The first independent evaluator review of the utilities' DAC-GT and CS-GT programs is scheduled for January 1, 2021.

As CCA programs will launch after the utilities' programs, MCE proposes that the first evaluation of the CCAs' programs not occur before January 1, 2022. MCE will work with Energy Division to determine the appropriate scope, funding level and budget allocations for CCAs to include the program evaluation in their budgets for program year (PY) 2022 and subsequent PYs.

In addition to budget forecasts, annual program budget submissions must also include details on program capacity and customer enrollment numbers for both programs:

1. Existing capacity at previous PY close;
2. Forecasted capacity for procurement in the upcoming PY;
3. Customers served at previous PY's close; and
4. Forecasted customer enrollment for the upcoming PY.

Finally, MCE will submit the following workpapers to Energy Division staff directly:

1. Workpaper for the calculation of the generation cost delta;
2. Workpaper for the calculation of the 20% bill discount to participating customers.

Supporting worksheets used in substantiating cost estimates, including direct labor, management and/or supervisor costs, and any vendor costs, along with a breakdown of staff or contractor position descriptions, loaded hourly rates, and total hours anticipated for each task, will be provided if available.

[31] Resolution E-4999 at p.27. The Resolutions determines that Program Administrators can submit a Tier 3 Advice Letter requesting an adjustment to the budget allocations if the need arises.

Program costs will not be charged to participating customers and will thus not appear on customers' bills. Instead, the cost categories described above will be tracked and charged as program costs to the DAC-GT and CS-GT programs.

MCE submits a budget estimate for PYs 2020 and 2021 in Attachment C to the Implementation Advice Letter.

5.2. Budget Forecasting and Reconciliation Procedures

MCE will file, by February 1 of each program year, a Tier 1 Budget Advice Letter.[32] In this Annual Budget Advice Letter filing, MCE will, for each program separately:

1. Request approval of its **forecasted budget** for the upcoming program year (e.g.; by February 1, 2021 for the 2022 PY);
2. Report its **actual expenditures** during the prior program year (e.g.; by February 1, 2021 for the 2020 PY); and
3. **Reconcile** the prior year's budget forecast with actual expenditures.

5.2.1. Budget Forecast

MCE will forecast estimated program cost for the upcoming PY for all budget categories described above. For the projected revenue loss associated with providing the 20% discount to customers, MCE will estimate the total expected revenue loss for the generation portion of the electric bill. PG&E will estimate the total expected revenue loss for the delivery portion of the electric bill.

5.2.2. Report Actual Expenditures

MCE will report on actual expenditures for the previous PY for all budget categories described above. For the actual revenue loss associated with providing the 20% discount to customers, MCE will report on the actual total revenue loss for the generation portion of the electric bill. PG&E will report on the total actual revenue loss for the delivery portion of the electric bill.

The Annual Budget Advice Letter will be the mechanism for the Commission and stakeholders to review MCE actual program costs and performance. Based on the information provided in MCE's Annual Budget Advice Letter, PG&E can include a summary of actual program expenditures for the previous PY in the ERRA Compliance Review.

5.2.3. Budget Reconciliation

In the Annual Budget Advice Letter, MCE will true up forecasted program costs against actual expenditures by budget category for the prior PY. Any unspent funds from the prior PY will be used to offset the forecasted budget for the upcoming PY. If actual expenditures exceeded the

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[32] The budgets for PY 2020 and 2021 are included as an attachment to this filing, hence no additional Tier 1 Advice Letter was required by February 1, 2020 for the 2021 PY.

forecast in the previous PY, MCE will add the shortfall to the forecasted budget for the upcoming PY.

5.3. Cost Recovery Procedures

Pursuant to D.18-06-027, the DAC-GT and CS-GT programs are funded first through available GHG allowance proceeds. If such funds are exhausted, the programs will be funded through public purpose program (PPP) funds. More specifically, if total forecasted annual program costs for the programs for all PAs in an IOU's service territory (i.e., IOU and CCAs) are less than the estimated GHG allowance revenues available for the programs in that IOU's service territory, all estimated program costs will be set aside from GHG allowance revenues. If total forecasted annual program costs for all PAs in an IOU service territory are greater than the GHG allowance revenues available for the programs, all available GHG allowance revenues will be set aside for the programs, and the shortfall in funds will be allocated to PPP funds.

D.18-06-027 authorizes CCAs to access GHG allowance revenues and/or PPP funds to run the DAC-GT and CS-GT programs.[33] The IOUs administer the GHG allowance revenues and collect PPP funds, and have established balancing accounts for the DAC-GT and CS-GT programs. CCAs are not in the position to either access those funds directly or establish balancing accounts to track program costs. Therefore, MCE requests that the Commission direct PG&E to modify its DAC-GT and CS-GT balancing accounts to include a sub-account to track the funding and costs of MCE's DAC-GT and CS-GT programs. Additionally, PG&E will be responsible for determining and tracking whether and how much of the funding for MCE's DAC-GT and CS-GT programs comes from GHG-allowance revenues versus PPP funds.

Once the Commission approves MCE's Annual Budget Advice Letter, PG&E will include the total budget estimate for the upcoming PY for MCE's DAC-GT and CS-GT programs in the ERRA Forecast filing due in early June of each year. Once PG&E receives approval of its ERRA Forecast from the Commission, PG&E will set aside the requested MCE budget in a sub-account of its DAC-GT and CS-GT balancing accounts. PG&E will then transfer program funds to MCE in four quarterly installments (by January 1, April 1, July 1 and October 1 of each year) for the upcoming quarter.[34]

If the ERRA Forecast is not approved by January 1 of a given PY, PG&E will transfer all past due funds to MCE within thirty days of issuance of such approval.

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[33] D.18-06-027, Ordering Paragraph 17, at p. 104.

[34] In 2020, depending on the timing of the Commission's approval of this Advice Letter, PG&E will include both the PY 2020 and PY 2021 budget estimates in its 2021 ERRA Forecast filing in early June or in its 2021 ERRA November update. Once the 2021 ERRA Forecast is approved, PG&E will transfer all past due PY 2020 funds within thirty days of issuance of such approval.

6. MARKETING, EDUCATION AND OUTREACH

MCE will establish a ME&O program to promote customer participation in the DAC-GT and CS-GT programs. MCE plans to directly implement the ME&O program and execute outreach.

MCE is submitting a ME&O plan for PYs 2020-2021 in Attachment D to the Implementation Advice Letter.[35] The ME&O plan discusses specific methods for customer outreach, including any coordination with local CBO sponsors and associated funding~~.~~ to market the CS-GT program. The plan addresses how MCE will work to identify residential customers in DACs who are likely eligible for the CARE and FERA programs, but who are not yet enrolled. Finally, the plan discusses how to leverage existing customer programs to market the ~~DAC-GT and~~ CS-GT programs.

As customers will be auto-enrolled to the DAC-GT program, ME&O efforts for this program will focus on customer education and awareness. MCE will provide customers with information about the program itself but will also use the opportunity to increase customer awareness about other energy savings opportunities, participation in other clean energy programs and rate options.

MCE will file annual ME&O plans and detailed budgets by February 1 of each year for the upcoming PY, starting in 2021.

7. REPORTING

Within 30 calendar days after the end of each calendar quarter, MCE will file a quarterly report for both programs, distinguishing between the DAC-GT and CS-GT program data. The quarterly report will detail:

- Procured capacity;
- Online capacity;
- DACs in which projects are located;
- Number of participating customers in each DAC within MCE's service territory;
- Number of customers who have successfully enrolled in CARE and FERA in the process of signing up for the DAC-GT or CS-GT programs.

The quarterly report will be filed in R.14-07-002 and served onto the same service list.

Semi-annually, within 30 calendar days after the end of each six-month period of the year, MCE will report the following information for CS-GT projects to the Commission's Energy Division Central Files:

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[35] The ME&O plan and budget for PY 2020 are subject to change depending on the date of approval of the Implementation Advice Letter.

- Number of income-qualified customers subscribed to each project and the capacity those customers are receiving;
- Whether a waitlist of non-income-qualified customers exist and the size of that list;
- If project sponsors are receiving bill credits under CS-GT projects and the size of each sponsor's subscription; and
- The number of master-metered properties served on the CS-GT tariff and the total capacity those properties are subscribed to receive.

MCE's first quarterly or semi-annual report will be filed on the first scheduled due date after customer enrollment begins.

8. PROGRAM MEASUREMENT AND EVALUATION

An independent evaluator will review the utilities' DAC-GT and the CS-GT programs every three years beginning in 2021.[36] The CS-GT program must also be assessed by the same independent evaluator one year after program launch.[37]

MCE proposes commencing independent evaluation for CCA DAC-GT and CS-GT programs at the beginning of the upcoming PY after customers have been enrolled under the program for a minimum of one full year (e.g. if the DAC-GT program were to launch with interim resources by the fall of 2020, the first program evaluation would occur on January 1, 2022). MCE will work with Energy Division to determine the appropriate scope, funding level and budget allocations for CCAs to include the program evaluation in their program budgets for PY 2022 and subsequent PYs.

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[36] The CPUC's Energy Division will select the independent evaluator through a Request for Proposal (RFP) process managed by San Diego Gas & Electric Company on behalf of the Commission. The RFP process will be led by staff from the Commission's Energy Division, and Energy Division staff will make the final decision on the winning bidder.

[37] Resolution E-4999 clarified that it is appropriate to interpret the first year of the CS-GT program as the first-year customers are able to subscribe to projects. Thus, if no customers have subscribed to CS-GT projects by 2021, the initial independent evaluator review in 2021 will replace the evaluation of the CS-GT program after the first year.

ELECTRIC SCHEDULE DAC-GT

DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM

Effective Date: [TBD upon Commission approval]

APPLICABILITY

The Disadvantaged Communities Green Tariff (DAC-GT) is a voluntary rate supplement to the customer's otherwise applicable rate schedule (OAS) under which eligible customers have their electricity usage met with up to 100% solar energy ~~based on their actual usage each month~~produced by a pool of community solar projects while also receiving a 20% discount on their OAS.

To enroll under the rate, a customer must meet the following eligibility requirements:

- Customers must receive electric generation service from MCE;
- Customer must be on a residential rate;
- Customer must meet the income eligibility requirements for the California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance (FERA) programs;
- The customer's service address must be located in a disadvantaged community (DAC). DACs are defined as communities that are identified in the CalEnviroScreen 3.0 tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data. In the event that the CalEnviroScreen tool is updated, enrolled customers will retain their eligibility even if their census tract is no longer considered an eligible DAC as defined above.

Service accounts enrolled under the following programs and services are ineligible to enroll under the DAC-GT rate:

- Standby service
- Net energy metering (NEM) rates;
- Non-metered service;
- Rates that are not CARE- or FERA-eligible;
- Non-residential rates;

- Master-metered customers;
- Customers enrolled in Community Solar Green Tariff (CS-GT) rate schedule.

Eligibility of customers is verified at the level of the Service Agreement ID (SA ID).

ENROLLMENT TERMS

Enrollment of customers under Schedule DAC-GT occurs at the level of the SA ID. Customer enrollment is capped at a maximum of 2 MW solar equivalent per SA ID. This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

Customers subscribe to a percentage of the total capacity of all solar resources under the program based on their previous 12-month average monthly usage.[1] This percentage allocation is set at the time of customer subscription but may be revisited periodically to ensure accurate allocations of project capacity.

Eligible MCE customers ~~may~~ residing within a top 10% of DAC census tract statewide that are located in MCE's service area will be automatically enrolled in the DAC-GT rate schedule up to the program cap. Priority will be given to customers who have made an effort to pay. The following groups will be progressively enrolled until the program capacity is reached:

- Customers who have made at least four (4) full or partial payments in the last eight (8) months
- Customers who have made at least three (3) full or partial payments in the last eight (8) months
- Customers who have made at least two (2) full or partial payments in the last eight (8) months

If there is insufficient program capacity to enroll ~~under the rate on a first-come, first-served~~all customers in a given category, customers from that category will be randomly selected for program enrollment. All remaining customers will be placed on a waitlist. MCE will monitor program attrition on a monthly basis ~~until customer subscriptions reach MCE's DAC-GT program cap. Once MCE reaches its program cap, a wait list will be maintained for new subscriptions. When~~and enroll additional customers from the waitlist as program capacity becomes available~~, MCE will continue enrolling eligible customers either from the waitlist (if applicable), or on a first-come, first-served basis up to the program cap.~~.

~~The customer will be placed on the DAC-GT rate on the first day of the next billing cycle where the billing cycle start date occurs at least five (5) business days after the date of the customer's request. A customer request that is received within five (5) business days of the customer's next billing cycle may result in the customer being placed on the DAC-GT rate in the following billing cycle.~~

[1] If previous 12-month historical usage is not available, the average monthly usage will be derived from as many months as available. For customers establishing new service, the class average monthly usage will be used.

A participating customer can remain on the DAC-GT tariff for up to 20 years from the time of enrollment. There is no contract required when enrolling in the DAC-GT program. Customers may ~~enroll~~remain enrolled for any number of months, and there is no enrollment or cancellation fee. Customers may choose to cancel participation in the program at any point in time. Cancellation of a customer's participation will become effective on the next meter read date; cancellations made within five (5) business days of the next meter read date may not be changed for an additional billing cycle.

A customer's service under this schedule is portable within MCE electric service area~~,~~ as long as the customer continues to live in a DAC as defined under the program and continues to meet all other eligibility requirements. If the customer is found to still be eligible, MCE retains their status as a program participant and does not require the customer to go on a waitlist, as long as the customer's turn-on date at the new location is within 90 days of their final billing date at their original location.

Customers who, after enrollment into the DAC-GT Program, become ineligible for CARE or FERA will be de-enrolled from the DAC-GT program.

RATES

Customers taking service on this rate schedule will receive a twenty (20) percent discount on the electric portion of the bill compared to their OAS. The discount applies as long as customers are enrolled under the programs and they comply with all the eligibility and enrollment terms.

For low-income customers enrolled in the CARE or FERA programs, the OAS is the customer's existing CARE or FERA rate. Accordingly, the 20% discount for these customers will be applied to low-income customer bills after the CARE/FERA discount has been applied.

For customers who are not enrolled in CARE or FERA programs, the ~~OAR~~OAS is the customer's existing rate schedule before program enrollment. Residential customer SA IDs that are already enrolled in MCE's 100% renewable energy generation service option (i.e., MCE's "Deep Green" rate) when enrolling under the programs, will be defaulted to MCE's base rate (i.e., MCE's "Light Green" rate) for the purposes of calculating the 20 percent discount.

BILLING

Monthly bills are calculated in accordance with the customer's OAS and the provisions contained herein. The amount credited under Schedule DAC-GT is provided by both PG&E and MCE: MCE calculates the twenty (20) percent discount for the generation portion of the electric bill and PG&E calculates the twenty (20) percent discount for the delivery portion of the electric bill.

Both entities display the discount on their respective portion of the customer's utility bill.

METERING

All customers must be metered according to the requirements of their OAS.

Budget Forecast for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs for the Program Years 2020 and 2021

Proposed by Marin Clean Energy

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October 16, 2020

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1. PURPOSE

Pursuant to Ordering Paragraph (OP) 17 of Decision (D.)18-06-027 *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities* and guidance provided in Resolution E-4999, MCE hereby submits this budget forecast for the Disadvantaged Communities Green Tariff (DAC-GT) and the Community Solar Green Tariff (CS-GT) programs for Program Years (PY) 2020 and 2021.[1]

MCE requests that the budgets proposed herein be approved by the Commission and that the Commission direct PG&E to transfer funds sufficient to meet MCE's approved annual budgets per the funding mechanisms discussed below.

2. BACKGROUND

Per Resolution E-4999, estimated budget forecasts must be presented by program and include the following budget line items:[2]

1. Generation cost delta, if any;[3]
2. 20 percent bill discount for participating customers (generation portion);
3. Program administration costs:
    a. Program management;
    b. Information technology (IT);
    c. Billing operations;
    d. Regulatory compliance; and
    e. Procurement.
4. Marketing, education and outreach (ME&O) costs:
    a. Labor costs;
    b. Outreach and material costs;
    c. Local CBO/ sponsor costs (for CS-GT only);
5. Program evaluation costs.

In addition to budget forecasts, annual program budget submissions also include details on program capacity and customer enrollment numbers for both programs. More specifically, MCE reports on

1. Existing capacity at previous PY's close;

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[1] In future program years, this annual program budget will also include actual program costs from the previous PY, as well as a reconciliation of forecasted versus actual costs.

[2] A detailed description of each budget line item can be found in MCE's Implementation Plan, submitted in Appendix A to the Implementation Advice Letter.

[3] Resolution E-4999 establishes that *above market* generation costs should include net renewable resource costs in excess of the otherwise applicable class average generation rate that will be used to calculate the customers' bills. In conversations with the CPUC's Energy Division after the release of the Resolution, it was clarified that this budget line item is intended to cover both a potential higher, as well as lower, cost of the DAC-GT/ CS-GT resources than the otherwise applicable class average generation rate. Hence, the term is updated to state the "*Delta of generation costs* between the DAC-GT/ CS-GT resources and the otherwise applicable class average generation rate".

2. Forecasted capacity for procurement in the upcoming PY;
3. Customers served at previous PY's close; and
4. Forecasted customer enrollment for the upcoming PY.

Finally, MCE will submit the following workpapers to the California Public Utilities Commission (CPUC or Commission) Energy Division staff directly:

1. Workpaper for the calculation of the generation cost delta;
2. Workpaper for the calculation of the 20% bill discount to participating customers.

Supporting worksheets used in substantiating cost estimates, including direct labor, management and/or supervisor costs, and any vendor costs, along with a breakdown of staff or contractor position descriptions, loaded hourly rates, and total hours anticipated for each task, will be provided if requested and available.

3. BUDGET FORECAST FOR PY 2020 AND 2021

For PYs 2020-2021, MCE requests a total budget of $ $1,~~992,897~~853,437 for the DAC-GT and CS-GT programs. A detailed budget forecast for each program and PY by budget line item can be found in the table below.

Table 1: MCE Budget Forecast for PYs 2020 and 2021

Tab	Category	DAC-GT			CS-GT			
		2020	**2021**	**Total**	**2020**	**2021**	**Total**	
1	Generation Cost Delta	$ 36,199	$ 796,342	**$ 832,541**	$ -	$ -	**$ -**	
2	20% Bill Discount	$ 7,564	$ 162,571	**$ 170,135**	$ -	$ -	**$ -**	
	Program Administration							
3a	Program Management	$ 118,820	$ 93,000	**$ 211,820**	$ 89,420	$ 125,400	**$ 214,820**	
3b	Information Technology	$ 24,814	$ 5,940	**$ 30,754**	$ 24,814	$ 9,090	**$ 33,904**	
3c	Billing Operations	$ 23,180	$ 34,830	**$ 58,010**	$ 5,970	$ 8,970	**$ 14,940**	
3d	Regulatory Compliance	$ 11,760	$ 6,480	**$ 18,240**	$ 11,760	$ 6,480	**$ 18,240**	
3e	Procurement	$ 20,295	$ 16,045	**$ 36,340**	$ 34,995	$ 21,445	**$ 56,440**	
	Subtotal Program Administration	**$ 198,869**	**$ 156,295**	**$ 355,164**	**$ 166,959**	**$ 171,385**	**$ 338,344**	
	Marketing, Education & Outreach							
41	Labor Costs	$ 47,040	$ 63,720	**$ 110,760**	$ 5,390	$ 14,364	**$ 19,754**	
4b	Outreach and Material Costs	$ 72,400	$ 34,250	**$ 106,650**	$ 3,000	$ 21,550	**$ 24,550**	
4c	Local CBO/ Sponsor Costs	$ -	$ -	**$ -**	$ 15,000	$ 20,000	**$ 35,000**	
	Subtotal ME&O	**$ 119,440**	**$ 97,970**	**$ 217,410**	**$ 23,390**	**$ 55,914**	**$ 79,304**	
5	EM&V	$ -	$ -	**$ -**	$ -	$ -	**$ -**	
Total		**$ 362,071**	**$ 1,213,178**	**$ 1,575,249**	**$ 190,349**	**$ 227,299**	**$ 417,648**	**$ 1,992,897**

Tab	Category	DAC-GT			CS-GT			
		2020	**2021**	**Total**	**2020**	**2021**	**Total**	
1	Generation Cost Delta	$ 36,199	$ 796,342	**$ 832,541**	$ -	$ -	**$ -**	
2	20% Bill Discount	$ 7,564	$ 162,571	**$ 170,135**	$ -	$ -	**$ -**	
	Program Administration							
3a	Program Management	$ 118,820	$ 93,000	**$ 211,820**	$ 89,420	$ 125,400	**$ 214,820**	
3b	Information Technology	$ 24,814	$ 5,940	**$ 30,754**	$ 24,814	$ 9,090	**$ 33,904**	
3c	Billing Operations	$ 23,180	$ 34,830	**$ 58,010**	$ 5,970	$ 8,970	**$ 14,940**	
3d	Regulatory Compliance	$ 11,760	$ 6,480	**$ 18,240**	$ 11,760	$ 6,480	**$ 18,240**	
3e	Procurement	$ 20,295	$ 16,045	**$ 36,340**	$ 34,995	$ 21,445	**$ 56,440**	
	Subtotal Program Administration	**$ 198,869**	**$ 156,295**	**$ 355,164**	**$ 166,959**	**$ 171,385**	**$ 338,344**	
	Marketing, Education & Outreach							
41	Labor Costs	$ 21,560	$ 43,740	**$ 65,300**	$ 5,390	$ 14,364	**$ 19,754**	
4b	Outreach and Material Costs	$ 5,650	$ 7,000	**$ 12,650**	$ 3,000	$ 21,550	**$ 24,550**	
4c	Local CBO/ Sponsor Costs	$ -	$ -	**$ -**	$ 15,000	$ 20,000	**$ 35,000**	
	Subtotal ME&O	**$ 27,210**	**$ 50,740**	**$ 77,950**	**$ 23,390**	**$ 55,914**	**$ 79,304**	
5	EM&V	$ -	$ -	**$ -**	$ -	$ -	**$ -**	
Total		**$ 269,841**	**$ 1,165,948**	**$ 1,435,789**	**$ 190,349**	**$ 227,299**	**$ 417,648**	**$ 1,853,437**

MCE provides the following clarifying notes regarding the budget summary.

Generation Cost Delta
MCE does not anticipate having *new* DAC-GT or CS-GT projects come online in 2020 or 2021 due to the need for soliciting such projects. However, for the DAC-GT program, MCE will use an interim project while new projects are being solicited and built. Hence, the generation cost delta budget forecast for the DAC-GT program is based on the cost of the interim resource selected. More detail is provided in the Implementation Plan in Appendix A to the Implementation Advice Letter.

20 Percent Bill Discount
As described in more detail in MCE's Implementation Plan, MCE proposes to only calculate the 20% discount for the generation portion of the electric bill. The respective utility (in MCE's case PG&E) will be responsible for calculating the 20% discount on the delivery portion of the bill for CCA program participants. Hence, the budget forecasted for providing the bill discount to customers for the DAC-GT program is based on the revenue loss experienced by providing a 20% discount on the generation portion of the electric bill, not the full electric bill.
As mentioned above, MCE does not expect to enroll customers in the CS-GT program in PYs 2020 or 2021 as new solar resources must be procured for this program.

Program Administration Costs
Program management includes program development and management, budgeting, and reporting. IT costs include the costs to develop program tools and updating existing systems to accommodate program enrollment and billing. Billing operations covers costs for ongoing billing operations and customer support once all systems are developed. Regulatory covers costs for regulatory compliance and related program filings with the Commission. Procurement covers the costs to develop and manage the solicitations for solar resources under the program, as well as annual renewable energy credit (REC) retirement and compliance functions.

Marketing, Education and Outreach (ME&O)
ME&O budgets are split in three categories – (1) MCE labor costs; (2) MCE direct costs for outreach and material; and (3) funds provided to the local CBOs who function as the sponsor for the CS-GT program.

Evaluation, Measurement and Verification (EM&V)
MCE proposes commencing independent evaluation for CCA DAC-GT and CS-GT programs at the beginning of the upcoming PY after customers have been enrolled under the program for a minimum of one full year (e.g., if the DAC-GT program were to launch with interim resources by the fall of 2020, the first program evaluation would occur on January 1, 2022). Hence, MCE does not include any budget forecast for EM&V in the budget for PYs 2020 and 2021.

~~5.~~4. BUDGET CAPS

Resolution E-4999 establishes a budget cap of 10% of the total budget for program administration costs and a budget cap of 4% of the total budget for ME&O costs.[4] However, administrative and ME&O costs may be higher than these budget allocations in the first two years of program implementation (i.e., PYs 2020 and 2021 for MCE), acknowledging that program start-up costs may be higher. Hence, MCE will only include information on budget caps in subsequent submissions of the Annual Budget Advice Letter.

~~6.~~5. PROGRAM CAPACITY AND ENROLLMENT NUMBERS

MCE reports forecasted program capacity and customer enrollment numbers for PYs 2020 and 2021 in the table below. MCE is unable to report on existing program capacity and customer enrollment numbers to date as the programs have not launched yet.

MCE is only reporting estimated program capacity and enrollment numbers for the DAC-GT program, as this program is expected to be served by an interim solar resource in MCE's portfolio while new resources are being procured specifically for the program. For the CS-GT program, MCE will procure new solar resources that are only expected to come online in 2022.

Table 2: Program Capacity and Enrollment Count for DAC-GT

Category	DAC-GT		
	2020	2021	Total
Estimated capacity to be procured (MW)	4.31	0	**4.31**
Estimated customer enrollment (#)	450	1686	**2136**

~~7.~~6. COST RECOVERY AND FUND TRANSFER PROCEDURES

Once the Commission approves MCE's budget request, PG&E will be responsible for including the total budget request for MCE's DAC-GT and CS-GT programs in the ERRA Forecast filing due in early June of each year (or in the ERRA Update in early November, as available). Once PG&E receives approval of its ERRA Forecast from the Commission, PG&E will set aside the requested MCE budget in a sub-account of its DAC-GT and CS-GT balancing accounts. PG&E will then transfer program funds to MCE in four quarterly installments (by January 1, April 1, July 1 and October 1 of each year) for the upcoming quarter.
For 2020 program funds, PG&E must transfer all past due funds within thirty days of approval of the 2021 ERRA Forecast filing.

~~8.~~7. CONCLUSION

MCE respectfully requests the Commission approve the budgets proposed herein and direct PG&E to transfer funds sufficient to meet MCE's approved annual budgets per the funding mechanisms discussed above.

[4] Resolution E-4999 determined that Program Administrators can submit a Tier 3 Advice Letter requesting an adjustment to the budget allocations if the need arises. See Resolution E-4999 at p.27.

Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs for Program Years 2020 and 2021

Proposed by Marin Clean Energy

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1. PURPOSE AND GOALS

MCE will develop and implement a targeted customer marketing, education, and outreach (ME&O) campaign under the Disadvantaged Communities Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs to ensure potential customers in disadvantaged communities (DACs) are aware of the opportunity to benefit from the programs. ~~MCE's ME&O strategy has four main goals:~~

MCE will develop and implement separate targeted customer marketing, education, and outreach (ME&O) campaigns for the DAC-GT and CS-GT programs due to the differing enrollment processes of the two programs. Eligible customers for DAC-GT will be identified and automatically enrolled in the program by MCE. Hence, no customer recruitment for program participation is required. Eligible customers for CS-GT will not be automatically enrolled in the program; instead will be required to opt their accounts into the program by completing an enrollment form.

MCE's ME&O strategy for the DAC-GT program has three main goals:

1. Notify DAC-GT customers that their account has been automatically enrolled in the program;

2. Provide information (i.e., FAQs) about the program;

3. Increase customer awareness of energy use, savings opportunities, other customer incentives, rate options (i.e. TOU), discounts, or programs.

The main goals of the CS-GT ME&O strategy are:

~~1.~~4. Enroll eligible customers in the ~~DAC-GT and~~ CS-GT ~~programs~~program;

~~2.~~5. Increase awareness of, and enrollment in, California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs;

~~3.~~6. Increase customer awareness of energy use, savings opportunities, other customer incentives, rate options (i.e. TOU), discounts, or programs;

~~4.~~7. Address barriers to program participation and leverage best practices to participation and ensure that outreach to DAC and hard-to-reach customers is accessible and equitable.

~~Throughout this process~~For both ME&O campaigns, MCE aims to achieve meaningful and diverse customer engagement through a culturally-competent, multilingual approach. ~~To achieve these goals~~For CS-GT, MCE will develop a targeted customer engagement campaign that leverages community-based marketing best practices such as:

- A mix of multilingual and culturally-competent communications including community advertising (e.g., banners, newsprint), geo-targeted digital ads, and direct mail, and

- Direct customer outreach and partnerships with community-based organizations (CBOs) and local government agencies.

Ultimately, MCE will measure ME&O program success for the CS-GT program by the number of customers enrolled in the ~~DAC-GT and CS-GT programs~~program. We will also measure program success by the overall number of customers reached, and the diversity of customers reached.

The following subsections provide additional details about MCE's ME&O approach for the DAC-GT and CS-GT programs.

2. GUIDING PRINCIPLES

MCE is committed to developing diverse and culturally appropriate communication strategies to ensure that stakeholders can participate in decisions and actions that impact their communities. As such, MCE commits to the following guiding principles throughout the ME&O engagement process for the DAC-GT and CS-GT programs. MCE aims to:

- Achieve diverse and meaningful engagement that reflects the demographics of DAC communities to ensure equitable outreach across race, income and age barriers;
- Maintain transparency and accessibility of information by bringing the information directly to customers in their neighborhood, their community, or interest space to better engage them in the process;
- Build a collaborative process with community partners to ensure barriers and benefits to participation are considered in the ME&O activities to the maximum extent possible.

3. TARGET AUDIENCE

~~Given enrollment specifications around the programs~~For the DAC-GT program. MCE will automatically enroll any eligible customers that live in one of the top 10% of DAC census tracts statewide that are located in MCE's service area. Priority will be given to customers who have made an effort to pay, as defined by at least 4 full or partial payments in the last 8 months (category 1). If program capacity remains unsubscribed after enrolling these customers, MCE will enroll additional customers in the following order:

- Customers who have made at least 3 full or partial payments in the past 8 months (category 2)
- Customers who have made at least 2 full or partial payments in the past 8 months (category 3)[1]

[1] MCE has the capacity to serve approximately 1,762 customers under the DAC-GT program, based on an alloted program capacity of 4.31MW. Based on data through August 2020, 1411 customers have made at least 4 payments in the past 8 months, 1604 customers have made at least 3 payments inte past 8 months and 1748 customers have made at least 2 payments in the past 8 months. Customer capacity calculated using an estimated annual project generation of 10,571.568 MWh (28% capacity factor) and assuming an average customer usage of 500 kWh per month.

If there is not enough program capacity to enroll all customers in each category under the DAC-GT program, customers from the respective category will be randomly selected for program enrollment. MCE will monitor program attrition on a monthly basis and enroll additional customers from the waitlist as appropriate.

The following table shows the list of eligible census tracts for DAC-GT auto-enrollment.

Figure 1. Qualifying Neighborhoods in MCE Service Territory for DAC-GT Auto-enrollment

90% Cal Enviroscreen Score			
Census Tract	**California County**	**ZIP**	**Nearby City (to help approximate location only)**
6013379000	Contra Costa	94804	Richmond
6013312000	Contra Costa	94565	Pittsburg
6013365002	Contra Costa	94801	Richmond
6013377000	Contra Costa	94801	Richmond

For the CS-GT program, the primary target audience for the ME&O strategy are existing and eligible CARE/FERA customers living in top 25% DAC communities statewide per CalEnviroscreen. In MCE's service area, DAC communities include customers in the following neighborhoods:

Figure ~~1.~~2. Qualifying Neighborhoods in MCE Service Territory for CS-GT

Census Tract	Nearby City (to help approximate location only)	ZIP	California County
6013305000	Antioch	94509	Contra Costa
6013320001	Martinez	94553	Contra Costa
6013302005	Oakley	94561	Contra Costa
6013312000	Pittsburg	94565	Contra Costa
6013310000	Pittsburg	94565	Contra Costa
6013311000	Pittsburg	94565	Contra Costa
6013314103	Pittsburg	94565	Contra Costa
6013314104	Pittsburg	94565	Contra Costa
6013313102	Pittsburg	94565	Contra Costa
6013309000	Pittsburg	94565	Contra Costa
6013313101	Pittsburg	94565	Contra Costa
6013379000	Richmond	94804	Contra Costa
6013365002	Richmond	94801	Contra Costa
6013377000	Richmond	94801	Contra Costa
6013382000	Richmond	94804	Contra Costa
6013376000	Richmond	94801	Contra Costa
6013380000	Richmond	94804	Contra Costa
6013375000	Richmond	94801	Contra Costa
6013381000	Richmond	94804	Contra Costa
6013358000	Rodeo	94572	Contra Costa
6013368002	San Pablo	94806	Contra Costa
6013366002	San Pablo	94806	Contra Costa
6013368001	San Pablo	94806	Contra Costa
6013364002	San Pablo	94806	Contra Costa
6013392200	San Pablo	94806	Contra Costa
6095250701	Vallejo	94590	Solano
6095250801	Vallejo	94592	Solano
6095250900	Vallejo	94590	Solano
6095251802	Vallejo	94589	Solano
6095251901	Vallejo	94589	Solano

4. ME&O TACTICS AND STRATEGIES

4.1. Communications and Media Content

A variety of communications and media content will be developed to promote the programs, including flyers and fact sheets, as well as content on MCE's website. This material will be translated and improved throughout the ME&O strategy via message testing to ensure it is culturally competent and effective. Additionally, for the CS-GT program, MCE will run social media campaigns, as well as print and digital advertisements, in multiple languages to encourage program enrollment. Direct mailing and email blasts will also be utilized to target customers.

4.2. Community Outreach

To meet ME&O goals, MCE will develop an outreach and engagement strategy leveraging the key community outreach tactics summarized below. The community outreach strategy will include a multilingual and culturally competent approach to engagement and consider the specific needs of DAC communities in MCE's service area. ~~Outreach~~CS-GT outreach will be informed by data (census tracks, 4013, etc.) in order to identify customers who are most likely to enroll in the programs.

4.2.1. Grassroots Outreach

MCE will conduct grassroots outreach to engage directly with community members at community events. MCE already regularly attends and sponsors many community events throughout its service area, including neighborhood festivals, farmers markets, holiday celebrations, and special events. Under the community outreach strategy for the ~~DAC-GT and~~ CS-GT programs, MCE will focus on expanding the breadth of events attended in DAC neighborhoods.

MCE will utilize the expertise of community leaders to identify impactful events and will offer workshops and webinars as appropriate. As community events and workshops are held, we will closely track the diversity in race, age and income of participants, to ensure that participation reflects census distribution demographics of the DAC communities. Additionally, we will maximize convenience of meetings and events to public transportation, and ensure events are ADA accessible.

Due to COVID-19, appropriate considerations will be made for MCE attendance at in-person events. When possible, in person community outreach will be replaced with virtual workshops, webinars and digital toolkits.

4.2.2. Partnerships with Community Based Organizations

Partnering with Community Based Organizations (CBOs) is a critical facet of MCE's ME&O plan. CBOs have intimate knowledge of the local communities they serve and will serve as valuable resources for how best to conduct outreach that makes sense for members of their communities. As MCE engages with CBO partners, we seek to establish open dialogue, build awareness and understanding among community members, identify community-specific issues, and develop methods for disseminating relevant information. For example, CBOs will help coordinate program-specific workshops to disseminate program information to their constituencies. MCE will provide funding for CBOs to conduct outreach ~~around~~for the ~~DAC-GT and~~ CS-GT ~~programs~~program.

Additionally, many other local City departments already conduct outreach in the same communities in which we will conduct program outreach. MCE will investigate and pursue opportunities to collaborate as appropriate.

4.3. Program Leveraging

California offers a plethora of clean energy, energy efficiency, and energy storage programs, with several of them targeting income-qualified customers or customers in DACs. Complementing the state's programs, MCE also has developed a wide range of in-house program offerings with many of them focusing on vulnerable customers. MCE's Single Point of Contact (SPOC) model provides "behind-the-scene" coordination with various programs and funding sources in order to provide MCE's customers with the comprehensive, streamlined "one-stop-shop" guidance they need to navigate and enroll in these different offerings, maximizing the benefit to the customers while interweaving the value of all leveraged programs.

Under the DAC-GT/CS-GT ME&O plan, MCE will leverage its relationships and interactions with customers through existing programs to inform, educate and encourage program participation through its SPOC model. For example, MCE will leverage the following programs for joint outreach efforts: MCE's newly developed Battery Energy Storage Programs, MCE's low-income solar program for homeowners, MCE's Low-Income Families and Tenants (LIFT) pilot that offers energy efficiency upgrades to low-income multifamily properties, and the MCEv program, an electric vehicle rebate program for low-income customers.

Additionally, MCE will pursue program leveraging with relevant programs run by partners and other local CBOs and government entities.

Figure ~~2.~~3. MCE ME&O Tactics and Strategies

Communications and Media Content

- Social Media*
- MCE Website
- Flyers/ fact sheets
- Print and digital advertisement
- Direct mailings
- Email blasts

Grassroots Outreach

- Community Events
- Workshops and Webinars
- Collaboration with Community Leaders

CBO Partnerships

- Joint outreach
- Funding support

Program Leveraging

- MCE Energy Storage Program(s)
- MCE low-income solar program
- MCE LIFT pilot
- MCEv program
- Other CA and local programs

Communications and Media Content

- Social Media
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- Community Events
- Workshops and Webinars
- Collaboration with Community Leaders

CBO Partnerships

- Joint outreach
- Funding support

Program Leveraging

- MCE Energy Storage Program(s)
- MCE low-income solar program
- MCE LIFT pilot
- MCEv program
- Other CA and local programs

*Component of CS-GT ME&O only. Due to auto enrollment provisions and to limit customer confusion about program eligibility, these tactics will not be used for the DAC-GT program.

5. METRICS TRACKING

Because MCE is using multiple tactics for ME&O, a variety of metrics will be used to evaluate the effectiveness of each effort. Our primary measure of effectiveness is the number of customers reached, which can be measured by:

- DAC-GT
  - Number of customers enrolled based on auto enrollment criteria;
  - Number of customers opting to cancel program participation.
- CS-GT
  - Total number of enrollees ~~in both the DAC-GT and CS-GT programs~~;
  - Total CARE and FERA enrollment achieved through ~~DAC-GT/~~ CS-GT outreach;
  - Total number of customers reached;
  - Diversity in race, age and income of event participants, with participation that reflects census distribution demographics of the DAC communities;
  - Direct mail and email - email click-through and open rates;
  - Indirect website visits and page views, social media engagement and impressions;
  - Total number of events and distribution of events by neighborhood.

By regularly monitoring these measures, MCE will be able to make changes in its approach or shift the mix of ME&O channels to improve the effectiveness of outreach, if necessary. Additionally, feedback from CBO partners, surveys, on-the-ground interactions, and message testing could alter the strategy pursued.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Expedited Application of Pacific Gas and Electric Company Under the Power Charge Indifference Adjustment Trigger. (U 39 E)	Application 20-09-014

JOINT PROTEST OF CALCCA AND THE JOINT CCAS TO THE EXPEDITED APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY UNDER THE POWER CHARGE INDIFFERENCE ADJUSTMENT TRIGGER MECHANISM

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On behalf of the Joint CCAs

October 19, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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JOINT PROTEST OF CALCCA AND THE JOINT CCAS TO THE EXPEDITED APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY UNDER THE POWER CHARGE INDIFFERENCE ADJUSTMENT TRIGGER MECHANISM

In accordance with Rule 2.6 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and with Judge Toy's October 13, 2020 ruling,[1] the California Community Choice Association ("CalCCA"),[2] Central Coast Community Energy ("3CE"),[3] CleanPowerSF,[4] East Bay Community Energy ("EBCE"),[5] Marin Clean Energy ("MCE"),[6] Peninsula Clean Energy Authority ("PCE"),[7] Pioneer Community Energy ("Pioneer"),[8] San José Clean Energy ("SJCE"),[9] Silicon Valley Clean Energy Authority

[1] On October 13, 2020, Administrative Law Judge Toy issued an e-mail ruling setting a shortened protest deadline of October 19, 2020, with replies due on October 23, 2020.
[2] Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, the California Community Choice Association has authorized the Joint CCAs to file this Joint Protest on its behalf.
[3] 3CE, formerly known as Monterey Bay Community Power Authority, is the community choice aggregator ("CCA") for Monterey, San Benito and Santa Cruz Counties and parts of San Luis Obispo County. Service will be initiated to some cities in and the county of Santa Barbara in 2021.
[4] CleanPowerSF is the CCA for the City and County of San Francisco operated by the San Francisco Public Utilities Commission.
[5] EBCE is the CCA for Alameda County.
[6] MCE is the CCA for Marin County, unincorporated Napa County, unincorporated Contra Costa County, unincorporated Solano County, and the Cities and Towns of American Canyon, Calistoga, Napa, St. Helena, Yountville, Benicia, Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Richmond, San Pablo, San Ramon, and Walnut Creek.
[7] PCE is the CCA for San Mateo County.
[8] Pioneer is the CCA for Placer County.
[9] SJCE is the CCA for the City of San José.

("SVCE"),[10] Sonoma Clean Power ("SCP"),[11] and Valley Clean Energy Alliance ("VCE")[12] (collectively "the Joint CCAs") hereby submit this protest to Pacific Gas and Electric Company's ("PG&E") *Expedited Application Under the Power Charge Indifference Adjustment Trigger*, submitted on September 28, 2020 ("Application").[13]

CalCCA and the Joint CCAs protest the Application on the basis that other ratemaking approaches, such as a 36-month amortization period of PG&E's Power Charge Indifference Adjustment ("PCIA") Undercollection Balancing Account ("PUBA") projected year end 2020 balance, will better achieve the Commission's dual goals of (1) avoiding rate shock for unbundled customers and (2) making bundled customers whole in a timely manner. The proposals discussed herein also could be coupled with a suite of modifications to the PCIA framework, potentially including the removal of the PCIA rate increase cap for 2021. The purpose of such modifications would be to avoid the complexities in tracking different vintages of PUBA balances, the potential for multiple trigger applications in the same year, and the administrative burdens of a never-ending cycle of expedited PUBA trigger applications. CalCCA and the Joint CCAs also protest PG&E's request to implement a new rate via a Tier 1 advice letter where a Tier 2 advice letter complies with General Order 96-B.

Finally, PG&E's proposed scope misses important issues that should be resolved as part of this proceeding. The proposed schedule infringes on parties' due process rights by limiting

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[10] SVCE is the CCA for unincorporated Santa Clara County, and the Cities and Towns of Campbell, Cupertino, Gilroy, Los Altos, Los Altos Hills, Los Gatos, Milpitas, Monte Sereno, Morgan Hill, Mountain View, Saratoga and Sunnyvale.

[11] SCP is the CCA for the Cities of Cloverdale, Cotati, Fort Bragg, Petaluma, Point Arena, Rohnert Park, Santa Rosa, Sebastopol, Sonoma, Willits and the Town of Windsor, and the Counties of Sonoma and Mendocino.

[12] VCE is the CCA for the cities of Davis and Woodland and the unincorporated areas of Yolo County.

[13] Application ("A.") 20-09-014, *Expedited Application of Pacific Gas and Electric Company (U 39 E) Under the Power Charge Indifference Trigger* (September 28, 2020) ("Application").

their opportunity to be heard to the instant Protest, with no reasonable opportunity to test on the record the factual and legal assertions in PG&E's Application and testimony.

I. CALCCA AND THE JOINT CCAS' INTERESTS

CalCCA is an advocacy coalition comprised of twenty-two active California Community Choice Aggregators ("CCAs") in addition to several emerging CCA communities. CalCCA represents the interest of California's community choice electricity providers in the legislature and at state regulatory agencies by advocating for a regulatory environment that supports the development and long-term sustainability of locally run CCAs throughout California.

Except for CleanPowerSF and SJCE, each of the Joint CCAs is governed by a Board of Directors comprised of elected officials who represent the individual cities and counties the CCA serves or an elected City Council.[14] CleanPowerSF is the City and County of San Francisco's CCA, which is operated by the San Francisco Public Utilities Commission. SJCE is the City of San José's CCA program, which is administered by the San José Community Energy Department.

CCA customers pay CCA-specific generation rates, which vary and are partially influenced by local mandates to procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation. As a result, CCA customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from the incumbent for-profit utility. In addition, CCA and other unbundled customers are subject to several non-bypassable charges, including the PCIA.

CalCCA and the Joint CCAs are the advocates for CCA customers in the local communities that formed them. Ensuring the accuracy of the PCIA and other charges CCA

[14] *See* Cal. Pub. Util. Code § 366.2.

customers pay, planning for changes to the PCIA, and protecting customers from the rate shock that can result, is a core directive for all CCAs and essential for any load-serving entity. PG&E seeks, through this Application, Commission approval to implement a rate increase for unbundled customers (including those of the CCAs) stemming from the balance within PG&E's PUBA and a corresponding rate decrease for bundled customers within PG&E's Energy Resource Recovery Account ("ERRA").[15] PG&E's proposed rate increase will, therefore, have a direct impact on CCA customers and as a result both CalCCA and the Joint CCAs have a real, present, tangible and pecuniary interest in this proceeding.

II. BACKGROUND AND PG&E'S REQUESTED RELIEF

The Commission adopted the PCIA to ensure that when customers of investor owned utilities ("IOUs") depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[16] The PCIA is set annually within PG&E's ERRA Forecast proceeding. The 2020 PCIA rates that customers are currently paying, and which underlie PG&E's requested relief in this proceeding, were set in Decision ("D.") 20-02-047.

In 2018, the Commission established a cap on "the change of the PCIA from one year to the next" where, starting "with forecast year 2020, the cap level of the PCIA rate should be set at 0.5 cents/kWh more than the prior year's PCIA, differentiated by vintage."[17] The PUBA is a record of the shortfall in revenue that is charged to departing load customers because PCIA rates are limited by the $0.005/kWh cap.[18] For each customer class and vintage, the per-kWh

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[15] Application, pp. 1-2.

[16] *See* Decision ("D.") 07-01-030; D.08-09-012; D.18-10-019, p. 3 (October 11, 2018).

[17] D.18-10-019, Conclusions of Law 19-20, Ordering Paragraph 9(a)-(c) (October 11, 2018).

[18] *Id.*; *see also* PG&E Advice Letter 5440-E, effective January 1, 2019.

difference between the capped 2020 PCIA rate and the uncapped 2020 PCIA rate (what might be called the "PUBA Differential") is multiplied by actual departed customer usage each month in 2020. The resulting monthly accumulation of the PUBA Differential from all departed customers, plus interest, is tracked in the PUBA.

Once the cumulative amount in PUBA reaches 7% of PG&E's forecasted 2020 PCIA revenue from departed load customers, PG&E must, within 60 days, file an expedited trigger application that proposes "a revised PCIA rate that will bring the projected PUBA balance below 7% and maintain the balance below that level until January 1 of the following year, when the PCIA rate adopted in that utility's ERRA forecast proceeding will take effect."[19]

Because PG&E presently projects a year-end PUBA balance of $252.8 million as of the August accounting close, PG&E filed the instant Application.[20] The Application proposes implementing a vintage-specific PUBA rate adder for departing load customers to bring PG&E's year-end 2020 PUBA balance to zero.[21] PG&E proposes to amortize the forecasted year-end PUBA balance over a 12-month period, beginning January 1, 2021 and concluding December 31, 2021, rather than over a one-month period (December 2020) to avoid what PG&E calculates would be a system average rate increase of 48.9% for unbundled customers.[22] PG&E contends its proposal will increase the system average rate for unbundled customers by $0.0055/kWh.[23] Concurrently, PG&E proposes to decrease bundled customer rates by $0.0068/kWh, which represents an approximate 3% reduction in bundled customer rates.[24]

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19 D.18-10-019, Ordering Paragraph 10.
20 Application, p. 2.
21 *Id*.
22 *Id.* at pp. 6-7.
23 *Id*., attached Kolnowski Declaration at para. 15 and Table 1.
24 *Id.* at 7.

III. GROUNDS FOR PROTEST

CalCCA and the Joint CCAs have identified the issues below as directly and substantially impacting their interests. The specific issues enumerated below should be considered preliminary matters that CalCCA and the Joint CCAs have identified as unjust and unreasonable or misaligned with Commission policy, rules or precedent. CalCCA and the Joint CCAs continue to examine the Application and to issue data requests, the first of which was issued on October 2, 2020. CalCCA and the Joint CCAs therefore reserve the right to address additional issues in the course of this proceeding as they arise through further review, analysis, discovery and investigation of all aspects of the Application.

A. A 36-Month Amortization Period of PG&E's PUBA Balance Will Better Achieve the Commission's Dual Goals of Avoiding Rate Shock for Unbundled Customers and Making Bundled Customers Whole.

CalCCA and the Joint CCAs agree with PG&E that amortizing the entire projected year-end PUBA balance in one month would not be a reasonable ratemaking approach. However, PG&E's proposal will also result in a dramatic one-year rate increase for departed customers. While the Application correctly notes that the purpose of the PUBA trigger mechanism is to ensure bundled customers are made whole in a timely manner,[25] it gives short shrift to the competing interest the Commission balanced when creating the cap-and-trigger mechanism: preventing the rate volatility departed customers had seen as a result of calculating prior years' PCIA rates.[26] That key consideration has only become more important with the advent of the Portfolio Allocation Balancing Account ("PABA") true-up, which, as the Joint CCAs have

25 *See id*. at 4 (explaining that D.18-10-019 "established a trigger mechanism with the PCIA cap to protect against excessive undercollections and enable the Commission to act quickly on such undercollections.")

26 D.18-10-019, pp. 85-86.

demonstrated in A.20-07-002, has only made the potential for rate volatility worse as projected year-end balances whipsaw from month to month due to various market forces.[27]

CalCCA and the Joint CCAs do not oppose PG&E's calculation of its projected year-end PUBA balance, its proposed concept of a PUBA adder, or its calculation of resulting rates assuming a one-year amortization. Rather, we suggest the Commission consider adopting a three-year amortization period for the 2020 PUBA balance to protect against the dramatic one-year increase that will result from PG&E's proposal. In addition, CalCCA and the Joint CCAs recommend that the Commission consider a suite of modifications to the PCIA framework, including removal of the PCIA rate cap for 2021, to avoid recurrent issues such as the complexities in tracking different vintages of PUBA balances, the potential for multiple trigger applications in the same year, or a never-ending cycle of trigger applications.

Finally, PG&E's proposed implementation of its requested PUBA adder rate through a Tier 1 advice letter is contrary to the directives of General Order 96-B. Because the PUBA adder would be a new rate mechanism, it should be implemented via a Tier 2 advice letter. Each of these issues is addressed in turn below.

1. PG&E's Proposal Will Result in a Dramatic One-Year Rate Increase.

The type of substantial rate increases that would result from PG&E's proposal are inconsistent with Commission policy underlying the adoption of the PCIA rate increase cap. In D.18-10-019, the Commission adopted that cap to provide unbundled customers a degree of "certainty and stability"[28] and to reduce "extreme PCIA price spikes and bill impacts"[29] in

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27 A.20-07-002, *Prepared Direct Testimony of Brian Dickman on Behalf of the Joint Community Choice Aggregators in Pacific Gas and Electric Company's 2021 ERRA Forecast Proceeding*, pp. 12-15 (September 24, 2020).

28 D.18-10-019, p. 15.

29 *Id*. at 85.

response to what several parties described as significant PCIA rate volatility due to annual swings in energy prices—precisely such as that seen here in PG&E's Application.[30] Guided by the need to ensure "reasonably predictable outcomes" for customers and to "promote certainty and stability" "within a reasonable planning horizon,"[31] the Commission established a 0.5 cent/kWh cap on PCIA annual rate increases,[32] and simultaneously implemented this "'trigger' mechanism" to promptly correct for long-term and significant cost-shifting from unbundled to bundled customers.[33]

While PG&E contends its proposal will increase the system average rate for unbundled customers by $0.0055/kWh, it provides the vintage-specific rates as follows:[34]

TABLE 1
PROPOSED PUBA RATE ADDER BY VINTAGE ($/KWH)

Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	$ 0.00518	$ 0.00739	$ 0.00731	$ 0.01008	$ 0.00726	$ 0.00745	$ 0.00704	$ 0.00748	$ 0.00696	$ 0.00640	$ 0.00682
Small L&P	$ 0.00497	$ 0.00708	$ 0.00701	$ 0.00966	$ 0.00695	$ 0.00714	$ 0.00674	$ 0.00717	$ 0.00667	$ 0.00613	$ 0.00654
Medium L&P	$ 0.00535	$ 0.00763	$ 0.00755	$ 0.01040	$ 0.00749	$ 0.00769	$ 0.00726	$ 0.00772	$ 0.00719	$ 0.00660	$ 0.00704
E19	$ 0.00490	$ 0.00699	$ 0.00692	$ 0.00953	$ 0.00686	$ 0.00705	$ 0.00665	$ 0.00708	$ 0.00659	$ 0.00605	$ 0.00645
Streetlights	$ 0.00413	$ 0.00589	$ 0.00583	$ 0.00804	$ 0.00578	$ 0.00594	$ 0.00561	$ 0.00596	$ 0.00555	$ 0.00510	$ 0.00544
Standby	$ 0.00375	$ 0.00534	$ 0.00528	$ 0.00728	$ 0.00524	$ 0.00538	$ 0.00508	$ 0.00541	$ 0.00503	$ 0.00462	$ 0.00493
Agriculture	$ 0.00463	$ 0.00661	$ 0.00654	$ 0.00901	$ 0.00649	$ 0.00666	$ 0.00629	$ 0.00669	$ 0.00623	$ 0.00572	$ 0.00610
E20 T	$ 0.00421	$ 0.00600	$ 0.00594	$ 0.00818	$ 0.00589	$ 0.00605	$ 0.00571	$ 0.00607	$ 0.00565	$ 0.00519	$ 0.00554
E20 P	$ 0.00453	$ 0.00647	$ 0.00640	$ 0.00882	$ 0.00635	$ 0.00652	$ 0.00615	$ 0.00654	$ 0.00609	$ 0.00560	$ 0.00597
E20 S	$ 0.00472	$ 0.00673	$ 0.00665	$ 0.00917	$ 0.00660	$ 0.00678	$ 0.00640	$ 0.00681	$ 0.00634	$ 0.00582	$ 0.00621
System Average PUBA Rate Adder by Vintage	$ 0.00493	$ 0.00703	$ 0.00695	$ 0.00958	$ 0.00690	$ 0.00709	$ 0.00669	$ 0.00711	$ 0.00662	$ 0.00608	$ 0.00649

While there may be a 0.55 cent/kWh average increase for all unbundled customers, a review of the vintage-specific rate increases in the last row of the table tells a clearer story of the impacts of PG&E's proposal. The PUBA adder alone will cause average PCIA rate increases under

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30 *See id*. at 82-86.
31 *Id*. at 15; *see also id.* at p. 155, Finding of Fact 18.
32 *Id*. at 86, 162, Ordering Paragraph 9.
33 *Id*. at 86-87, 162, Ordering Paragraph 9.
34 Application, attached Kolnowski Declaration at para. 15 and Table 1.

PG&E's proposal between 0.49 cent/kWh and 0.96 cents/kWh, the latter being nearly *double* the permitted annual rate increase under D.18-10-019.[35]

Under PG&E's proposal, that increase is only the first of a two-part PCIA increase. To see the full impact to departed customers' PCIA rates for 2021, one must also consider the PCIA increase currently being addressed in PG&E's 2021 ERRA Forecast proceeding, A.20-07-002. To date, no party in that proceeding has disputed, and PG&E confirmed in response to discovery in this case,[36] that the projected revenue requirements in the 2021 ERRA forecast case will result in customers in the 2009 to 2018 vintages paying capped PCIA rates, *i.e.*, PCIA rates that are \$0.005/kWh higher than their 2020 PCIA rates. Factoring in those forecasted rate increases for 2021, the effective PCIA rate under PG&E's proposal, *i.e.*, PG&E's proposed PUBA adder plus the capped PCIA rates likely to be approved in A.20-07-002, shows a total impact as follows: [37]

Table 1: Effective PCIA Rates – Capped 2021 PCIA Rates Plus PG&E's Proposed PUBA Adder (12-month Amortization)

	Combined 2021 PCIA Rates + PUBA Rate Adder											
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	0.03603	0.04140	0.04377	0.04641	0.04575	0.04641	0.04581	0.04611	0.04554	0.04500	0.03900	0.03188
Small L&P	0.03483	0.04000	0.04229	0.04483	0.04421	0.04485	0.04428	0.04456	0.04401	0.04350	0.03768	0.03086
Medium L&P	0.03709	0.04262	0.04506	0.04778	0.04709	0.04777	0.04716	0.04747	0.04688	0.04632	0.04015	0.03280
E19	0.03415	0.03923	0.04147	0.04397	0.04335	0.04398	0.04341	0.04370	0.04315	0.04265	0.03696	0.03023
Streetlights	0.02871	0.03299	0.03488	0.03698	0.03645	0.03698	0.03650	0.03675	0.03629	0.03586	0.03108	0.02541
Standby	0.02599	0.02986	0.03157	0.03348	0.03299	0.03347	0.03304	0.03326	0.03284	0.03245	0.02813	0.02300
Agriculture	0.03224	0.03704	0.03916	0.04152	0.04093	0.04152	0.04099	0.04126	0.04074	0.04026	0.03489	0.02853
E20 T (Excluding FPP)	0.02932	0.03368	0.03561	0.03775	0.03722	0.03776	0.03727	0.03752	0.03705	0.03661	0.03173	0.02596
E20 P (Excluding FPP)	0.03143	0.03611	0.03818	0.04049	0.03990	0.04048	0.03996	0.04023	0.03972	0.03925	0.03402	0.02780
E20 S (Excluding FPP)	0.03305	0.03796	0.04013	0.04254	0.04195	0.04256	0.04201	0.04229	0.04176	0.04127	0.03576	0.02928
System Average PCIA Rate by Vintage	0.03428	0.03938	0.04163	0.04415	0.04351	0.04415	0.04358	0.04386	0.04332	0.04281	0.03710	0.03069
% Increase vs. Current Rates	**41%**	**44%**	**40%**	**49%**	**38%**	**38%**	**37%**	**38%**	**37%**	**35%**	**10%**	-

As the last line in Table 1 shows, PG&E's proposal would result in an increase in the PCIA rate between 25% and 49% for every vintage except the 2019 and 2020 vintages. Such rate increases are incompatible with Commission policy to protect customers from unpredictable and substantial rate increases.

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35 *See* D.18-10-019, Ordering Paragraph 9 (establishing a 0.5 cent/kWh cap on the PCIA rate).

36 PG&E Response to Joint CCAs Data Request 1.01(c).

37 PG&E Response to Joint CCAs Data Request 1.01(c), (d).

2. A Longer Amortization Period or Reduced Revenue Requirement Would Protect Departed Customers from Rate Shock.

In contrast, a three-year amortization of the full 2020 year-end PUBA balanced would halve the projected PCIA rate increases compared to PG&E's proposal. Under a three-year amortization period, the PUBA adder in 2021 would be as follows:

Table 2: PG&E's Proposed PUBA Adder (36-month Amortization)

	Proposed PUBA Rate Adder by Vintage											
Rate Group	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.00173	0.00246	0.00244	0.00336	0.00242	0.00248	0.00235	0.00249	0.00232	0.00213	0.00227	-
Small L&P	0.00166	0.00236	0.00234	0.00322	0.00232	0.00238	0.00225	0.00239	0.00222	0.00204	0.00218	-
Medium L&P	0.00178	0.00254	0.00252	0.00347	0.00250	0.00256	0.00242	0.00257	0.00240	0.00220	0.00235	-
E19	0.00163	0.00233	0.00231	0.00318	0.00229	0.00235	0.00222	0.00236	0.00220	0.00202	0.00215	-
Streetlights	0.00138	0.00196	0.00194	0.00268	0.00193	0.00198	0.00187	0.00199	0.00185	0.00170	0.00181	-
Standby	0.00125	0.00178	0.00176	0.00243	0.00175	0.00179	0.00169	0.00180	0.00168	0.00154	0.00164	-
Agriculture	0.00154	0.00220	0.00218	0.00300	0.00216	0.00222	0.00210	0.00223	0.00208	0.00191	0.00203	-
E20 T (Excluding FPP)	0.00140	0.00200	0.00198	0.00273	0.00196	0.00202	0.00190	0.00202	0.00188	0.00173	0.00185	-
E20 P (Excluding FPP)	0.00151	0.00216	0.00213	0.00294	0.00212	0.00217	0.00205	0.00218	0.00203	0.00187	0.00199	-
E20 S (Excluding FPP)	0.00157	0.00224	0.00222	0.00306	0.00220	0.00226	0.00213	0.00227	0.00211	0.00194	0.00207	-
System Average PCIA Rate by Vintage	0.00164	0.00234	0.00232	0.00319	0.00230	0.00236	0.00223	0.00237	0.00221	0.00203	0.00216	-

Adding these PUBA Adder amounts to the vintage-specific PCIA rates likely to be adopted in A.20-07-002 would result in the following effective 2021 PCIA rates:

Table 3: Effective PCIA Rates – Capped 2021 PCIA Rates Plus PG&E's Proposed PUBA Adder (36-month Amortization)

	Combined 2021 PCIA Rates + PUBA Rate Adder											
Rate Group	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.03258	0.03647	0.03889	0.03969	0.04091	0.04144	0.04112	0.04113	0.04090	0.04073	0.03445	0.03188
Small L&P	0.03152	0.03528	0.03762	0.03839	0.03958	0.04009	0.03978	0.03979	0.03957	0.03941	0.03333	0.03086
Medium L&P	0.03353	0.03753	0.04002	0.04085	0.04210	0.04265	0.04232	0.04232	0.04209	0.04192	0.03545	0.03280
E19	0.03088	0.03457	0.03686	0.03762	0.03878	0.03928	0.03898	0.03898	0.03876	0.03861	0.03265	0.03023
Streetlights	0.02596	0.02906	0.03099	0.03163	0.03260	0.03302	0.03276	0.03277	0.03259	0.03246	0.02745	0.02541
Standby	0.02349	0.02630	0.02804	0.02862	0.02950	0.02988	0.02965	0.02965	0.02949	0.02937	0.02484	0.02300
Agriculture	0.02915	0.03263	0.03480	0.03551	0.03660	0.03708	0.03679	0.03680	0.03659	0.03645	0.03082	0.02853
E20 T (Excluding FPP)	0.02651	0.02968	0.03165	0.03230	0.03329	0.03372	0.03346	0.03347	0.03328	0.03315	0.02804	0.02596
E20 P (Excluding FPP)	0.02841	0.03180	0.03391	0.03461	0.03567	0.03614	0.03586	0.03586	0.03566	0.03552	0.03004	0.02780
E20 S (Excluding FPP)	0.02991	0.03347	0.03570	0.03642	0.03755	0.03804	0.03774	0.03775	0.03754	0.03739	0.03162	0.02928
System Average PCIA Rate by Vintage	0.03099	0.03469	0.03700	0.03776	0.03892	0.03942	0.03912	0.03912	0.03890	0.03875	0.03277	0.03069
% Increase vs. Current Rates	**27%**	**27%**	**25%**	**28%**	**23%**	**23%**	**23%**	**23%**	**23%**	**22%**	**-3%**	NA

The last line in Table 3 shows that the resulting increase in the PCIA rate for departed customers would result in rates increasing between 22% and 28% for every vintage except the 2019 and 2020 vintages.[38]

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38 The decrease in the 2019 vintage is due to a rate refund due to bundled customers overcollections in 2019. That issue is being addressed in A.20-07-002 and is unrelated to the CalCCA and Joint CCAs' proposals here in this case.

Critical to both the CCA proposal and PG&E's proposal is the fact that D.18-10-019 does not tie the Commission's hands in terms of the different revenue requirements and ratemaking proposals the Commission can adopt as a result of the Application. While Ordering Paragraph 10 includes a number of directives regarding the trigger mechanism, sub-sections 10.b and 10.d only govern what PG&E must *propose* as part of its PUBA trigger application.[39] Neither those sub-sections, Ordering Paragraph 9, nor other sections of D.18-10-019 more generally dictate the specific revenue requirements, ratemaking mechanisms, or amortization periods the Commission must adopt.[40] The requirements in Ordering Paragraph 9, for example, are met by ensuring that the entirety of the year-end 2020 PABA balance is addressed as part of this proceeding, with a portion of that balance incorporated into the 2021 PCIA rate calculation.[41]

D.18-10-019's approach provides the Commission flexibility to address special circumstances as they arise, such as those presented here, where amortizing PG&E's entire year-end PUBA balance over either a one-month or 12-month period would result in the rate volatility the Commission sought to avoid when establishing the cap-and-trigger mechanism in the first place.

B. The Three-Year Amortization Requested in This Protest Could Form Part of a More Holistic Resolution of Cap and Trigger Issues.

The CCA proposals herein could be coupled with a suite of modifications to the PCIA framework, potentially including the removal of the PCIA rate cap in 2021, aimed at avoiding (1) complexities in tracking different vintages of PUBA balances, (2) the potential for multiple trigger applications in the same year, and (3) the likelihood of a never-ending cycle of trigger applications.

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[39] D.18-10-019 at Ordering Paragraph 10.

[40] *See id*. at Ordering Paragraphs 9 and 10.

[41] *See id*. at Ordering Paragraph 9.c.

As Southern California Edison ("SCE") pointed out in its testimony supporting its October 9, 2020 PUBA trigger Application, the concept of a PUBA adder presents complexities in accounting and tracking PUBA-related revenue requirements. At the same time the 2020 PUBA adder will be paying off the 2020 PUBA balance, there is likely to be a 2021 PUBA balance accruing due to the likelihood of capped PCIA rates in 2021.[42] The same scenario applies to PG&E. The problem is how to track the status of a PUBA balance related to 2020, which will be reducing the overall PUBA balance as the PUBA adder is collected, at the same time as a PUBA balance related to 2021, which will be increasing the overall PUBA balance due to the PUBA Differential accruing from the capped PCIA rates charged to unbundled customers during 2021. The difficulty will be in ensuring that customers in the 2020 vintage, *i.e.*, currently bundled customers, do not pay for the 2020 PUBA revenue requirement in the event of a PUBA trigger in 2021.

In response to discovery raising this issue, PG&E suggested as follows:

> PG&E will maintain workpapers to track the portion of the PUBA balance that is authorized to be amortized in this proceeding and the portion that is accruing as a balance related to the capped 2021 PCIA rates, authorized in the 2021 ERRA Forecast Application (A.20-07-002). Specifically, upon the authorization of this Application and rate proposal in PG&E's 2021 ERRA Forecast Application (A.20-07-002), PG&E will maintain workpapers supporting the monthly PUBA entries that:
>
> A. Track the portion of the PUBA balance that is authorized to be recovered in this application through the PUBA Trigger Rate Adders;
> B. Track the portion of the PUBA balance that is not disposed of in this application, if any; and
> C. Track the portion of the PUBA balance caused by the departed load capped 2021 PCIA rates authorized in A.20-07-002.

[42] *See* A.20-10-007, *Expedited Application of Southern California Edison Company (U 338-E) Regarding Power Charge Indifference Adjustment Trigger*, *Testimony in Support of Expedited Application of Southern California Edison Company (U 338-E) Regarding Power Charge Indifference Adjustment Trigger*, 15:17-21 (Oct. 9, 2020) ("SCE Prepared Testimony").

> The sum of (B) and (C) will be considered in the 2021 PUBA Trigger Application when the 7% filing level is reached.[43]

Such an approach would be needed for each trigger that occurs in each year, and any leftover trigger revenue requirement balance in each year will be disposed of either via the following year's PCIA rates, or will remain in the PUBA for the following year, depending on the level of the PCIA cap in the applicable year.[44]

Although PG&E's approach may be able to track the PUBA balances, there is no question that it is complex, and tracking to ensure each vintage is only paying its fair share will be difficult. In addition, such tracking will only become more complex if the PUBA trigger threshold is hit year after year. In fact, as SCE points out in its testimony,[45] another trigger is likely to occur in 2021 on account of that 2021 PUBA Trigger balance, and there is little reason to think the situation is different for PG&E given the large PUBA differential between capped and uncapped rates currently forecasted in A.20-07-002.

PG&E's proposal does not address the overarching structural problem, which necessitates a longer-term solution. CalCCA and the Joint CCAs propose the Commission consider making the three-year amortization proposal suggested above part of a larger package of solutions that addresses cap and trigger issues more holistically. For example, assuming the Commission adopts the Working Group Three Report proposed in R.17-06-026, CalCCA and the Joint CCAs would support approving in the appropriate proceedings a three-year amortization for both (1) the year-end 2020 PUBA balance; and (2) the increase required to adjust PCIA rates to the uncapped 2021 PCIA revenue requirement to be established in A.20-07-002. Establishing such

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43 PG&E Response to Joint CCAs Data Request 1.03(a).

44 PG&E Response to Joint CCAs Data Request 1.03(b).

45 *See* SCE Prepared Testimony at 16:2.

an amortization in advance would also eliminate the filing of a PUBA trigger application in 2021 and would result in the following effective 2021 PCIA rates:

Table 4: Effective PCIA Rates – Uncapped 2021 PCIA Rates Plus PG&E's Proposed PUBA Adder (36-month Amortization for Both)

	Combined 2021 PCIA Rates + PUBA Rate Adder											
Rate Group	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.03121	0.03618	0.03837	0.03981	0.04048	0.04090	0.04073	0.04077	0.04086	0.04078	0.03950	0.03891
Small L&P	0.03002	0.03480	0.03691	0.03830	0.03894	0.03934	0.03918	0.03922	0.03930	0.03924	0.03798	0.03739
Medium L&P	0.03217	0.03729	0.03955	0.04104	0.04173	0.04216	0.04199	0.04203	0.04211	0.04204	0.04072	0.04013
E19	0.02954	0.03425	0.03632	0.03769	0.03832	0.03872	0.03856	0.03859	0.03868	0.03861	0.03739	0.03683
Streetlights	0.02488	0.02883	0.03058	0.03173	0.03227	0.03260	0.03247	0.03250	0.03256	0.03251	0.03149	0.03102
Standby	0.02253	0.02612	0.02770	0.02874	0.02923	0.02953	0.02941	0.02944	0.02950	0.02945	0.02852	0.02811
Agriculture	0.02791	0.03235	0.03431	0.03560	0.03620	0.03657	0.03643	0.03646	0.03654	0.03647	0.03532	0.03480
E20 T (Excluding FPP)	0.02536	0.02940	0.03118	0.03235	0.03290	0.03323	0.03310	0.03313	0.03320	0.03314	0.03209	0.03162
E20 P (Excluding FPP)	0.02726	0.03160	0.03352	0.03478	0.03536	0.03573	0.03558	0.03561	0.03569	0.03563	0.03451	0.03401
E20 S (Excluding FPP)	0.02850	0.03304	0.03504	0.03636	0.03697	0.03735	0.03720	0.03723	0.03731	0.03725	0.03606	0.03550
System Average PCIA Rate by Vintage	0.02976	0.03450	0.03659	0.03797	0.03861	0.03901	0.03885	0.03888	0.03897	0.03890	0.03768	0.03731
% Increase vs. Current Rates	**22%**	**26%**	**23%**	**28%**	**22%**	**22%**	**22%**	**22%**	**23%**	**23%**	**11%**	NA

Not only would these rate increases be more reasonable than those resulting from a 12-month amortization, they would also eliminate the potential for a PUBA trigger in 2021. By addressing the entire 2021 PABA balance and avoiding capped rates in 2021, there will be no PUBA Differential and no balance accruing to PUBA in 2021 from the 2021 PCIA revenue requirement. Avoiding a trigger in 2021 would allow the Commission and stakeholders to pursue more permanent solutions to the rate volatility caused by the implementation of the PABA true-up and the cap-and-trigger mechanism.

C. PG&E Should be Directed to Implement its Proposed Rate Increase Through a Tier 2 Advice Letter.

PG&E proposes that its requested rate change be implemented through a Tier 1 Advice Letter.[46] Per General Order 96-B Energy Industry Rules 5.1(3) and 5.2(1), a change to a utility charge via a Tier 1 advice letter is inappropriate where it is the first time a utility is using a particular index or formula. This is the first time PG&E would be implementing the PUBA adder for unbundled customers. 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 potential for calculation errors as the final year-end PUBA balance is calculated.

IV. PROPOSED SCOPE OF ISSUES

In addition to the two issues identified for consideration by PG&E in the Application,[47] Joint CCAs propose the following issues for the Commission's consideration in this proceeding:

- Whether the Commission should adopt a projected $252.8 million undercollection of the PUBA;
- Whether the Commission should find PG&E's request to refund bundled customers just, reasonable and consistent with appropriate Commission decisions;
- Whether PG&E's proposed 12-month amortization period beginning on January 1, 2020 and ending December 31, 2020 would result in just and

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[46] *See* Application, Vega declaration at Para 14.
[47] *Id*. at 9.

reasonable rates or whether other ratemaking mechanisms would be more appropriate;

- How the Commission can ensure coordination and alignment between A.20-07-002 (the PG&E 2021 ERRA Forecast proceeding) and the instant Application to allow for solutions that both avoid the potential for rate shock and ensure bundled customers will be made whole; and
- Whether PG&E should implement its proposed rate increase in a Tier 1 or a Tier 2 advice letter.

As previously stated, these issues are preliminary and Joint CCAs continue to examine the Application and to pursue discovery. Therefore, the Joint CCAs reserve the right to modify any of the proposals made herein and to address additional issues that may arise through further review, analysis, discovery and investigation of all aspects of the Application over the course of this proceeding.

V. CATEGORIZATION OF PROCEEDING, NEED FOR HEARINGS, AND PROPOSED PROCEDURAL SCHEDULE

The Joint CCAs agree with PG&E's proposed classification of this proceeding as "ratesetting."[48]

The Joint CCAs have raised herein a number of material issues of disputed fact within this Protest that require further record development. While evidentiary hearings may not be necessary to resolve these issues, parties' due process rights require more than an initial protest opportunity to substantively vet and resolve the issues raised by this application. PG&E's proposed schedule excludes any type of mechanism to allow sufficient record development, such

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[48] *Id*. at 8.

as workshops, testimony, hearings, and even legal briefing, and all but prohibits parties from proposing alternatives to PG&E's proposed resolution of this docket. Clearly, due process requires more opportunities for parties to test the assertions put forward in PG&E's Application and to propose and vet alternatives.[49] Indeed, the substantial customer rate impacts proposed in this Application caution against the Commission rushing disposition of this proceeding, and further factual development is needed on a number of issues even if a 12-month amortization process is used.

As a result, the Joint CCAs propose adopting a procedural schedule that will allow for further investigation yet still provide for timely resolution of these issues. Specifically, Joint CCAs propose including a technical workshop to work through the complex structural modifications and rate impacts raised by the Application and this Protest, in addition to filing opening and reply briefs to discuss and resolve these issues. This proposal is consistent with the procedural schedule recently adopted by the Commission in San Diego Gas & Electric's expedited application under the PCIA trigger mechanism in A.20-07-009:[50]

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[49] *See Pacific Gas & Electric Co. v. Pub. Util. Comm'n*, 237 Cal. App. 4th 812, 859-60 (2015) (quoting *Mullane v. Cent. Hanover Bank & Trust Co.*, 339 U.S. 306, 314 (1950)) ("notice reasonably calculated, under all the circumstances, to apprise interested parties of the pendency of the action and afford them an opportunity to present their objections."); *People v. Western Air Lines, Inc.*, 42 Cal. 2d 621, 632 (1954) ("[d]ue process as to the commission's initial action is provided by the requirement of adequate notice to a party affected and an opportunity to be heard before a valid order can be made."); *People v. Ramirez*, 25 Cal. 3d 260, 268 (1979) (citing *Morrissey v. Brewer*, 408 U.S. 471, 481 (1972)) ("it must be remembered that 'due process is flexible and calls for such procedural protections as the particular situation demands.'"); *id.* at 269 (an analysis of whether due process has been afforded should consider the private interest affected by the official action and the "risk of an erroneous deprivation of such interest through the procedures used, and the probable value, if any, of additional or substitute procedural safeguards," as balanced against any countervailing governmental interest).

[50] *See* A.20-07-009, Assigned Commissioner's Scoping Memo and Ruling, pp. 4-5 (October 7, 2020).

Date	Event
September 28, 2020	Application Filed
October 19, 2020	Protests to Application Filed
October 23, 2020	Reply to Protests
October 30, 2020	Prehearing Conference
November 9, 2020	Technical Workshop
November 11, 2020	Meet and Confer to Stipulate to Admission of Exhibits
November 24, 2020	Opening Briefs
November 30, 2020	Reply Briefs

VI. COMMUNICATIONS AND SERVICE

CalCCA and the Joint CCAs consent to "email only" service and request that the following individuals be added to the service list for A.20-09-014 on behalf of CalCCA and the Joint CCAs:

Party Representative for CalCCA:

Evelyn Kahl
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Party Representative For each of the Joint CCAs, please list each CCA as a party to the proceeding with Mr. Lindl as the representative for that party:

Tim Lindl
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Information Only: Please include the Joint CCAs' representative listed below on the information-only list for this proceeding:

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VII. CONCLUSION

For the foregoing reasons, CalCCA and the Joint CCAs respectfully request that the Commission grant CalCCA and each of the Joint CCAs party status and adopt the scope, categorization, and procedural schedule proposed above to fully examine and resolve the issues raised in this protest.

Respectfully submitted,

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Counsel to the Joint CCAs

Dated: October 19, 2020

CalCCA's Reply Comments on CAISO's Business Practice Manual (BPM) Change Proposed Revision Request (PRR) 1280

Submitted by	Company	Date Submitted
Evelyn Kahl evelyn@cal-cca.org (415) 254-5454	California Community Choice Association	October 20, 2020

I. Summary

CalCCA submits the following reply comments on the revised PRR 1280 and the ISO's responses to initial stakeholder comments posted on October 6, 2020. CalCCA opposes the PRR as it represents a significant shift in policy, which could have a material impact on rates, taken without the necessary procedural actions and its implementation schedule provides insufficient notice to affected load-serving entities (LSEs).

II. CAISO's PRR 1280

CAISO's PRR 1280 goes far beyond the realm of "implementation details" appropriate for changes to the BPM. Rather, the effects of PRR 1280 would significantly alter how the contributions of Demand Response (DR) resources are valued in meeting the state's reliability requirements. DR has long been considered by California policymakers as a preferred resource, and investment in DR programs that meet energy and reliability needs is therefore prioritized by LSEs. CAISO's proposal would undermine the value of these resources. Not only is this a significant policy shift, the BPM change could materially impact rates by effectively ignoring approximately 1,500 MWs of DR that have already been contracted for. This will appear as a sudden reduction in capacity and could lead to the CAISO identifying a system shortfall and procuring additional capacity, the cost of which will again be borne by customers. The significance of this change and the risk it introduces of increasing rates to California customers makes the BPM process an inappropriate venue for consideration.

III. CAISO's Responses to Initial Comments of Stakeholders

CalCCA provides comments below on select responses from the CAISO to issues raised in initial stakeholder comments.

a. The timing of CAISO's proposed BPM change provides insufficient notice to affected LSEs

Comment: It does not seem appropriate that this PRR could go into effect even while a potential appeal is pending.
CAISO Response: The CAISO is following its established BPM change management process.

As described in Section I above, the proposed BPM change would ignore DR resources historically applied as credits to CPUC-jurisdictional LSEs' system RA requirements. Since 2006, the CPUC has allocated the reliability contribution of IOU reliability resources, including DR resources, to its jurisdictional LSEs, reducing their system RA obligations by each LSE's proportional load-share. These allocations have already been administered for the 2021 RA year and LSEs have procured resources and prepared for their year-ahead filings, due 11 days from now, based on that information. For the CAISO to move forward with a change that affects the 2021 RA compliance protocols while LSEs rush to complete their year-ahead submissions is unreasonable and irresponsible. In fact, it seems likely that the BPM change will not be finalized until after the October 31st deadline for RA filings. Therefore, not only has CAISO not allowed sufficient time for LSEs to understand or respond to the BPM change in advance of its application, CAISO is proposing to retroactively change its reliability requirements for LSEs to be in direct conflict with the CPUC's current practices. Any change the CAISO makes to its rules around reliability requirements should be done in concert with the CPUC, such that both agencies are able to provide sufficient advance notice of the change and consistent guidance regarding its implications.

b. The proposed BPM change is procedurally defective

Comment: PRR1280 exceeds Board authority from Slow Demand Response initiative.
CAISO Response: Questions regarding LRA crediting were highlighted in the Slow Demand Response initiative but concerns on this matter cut across all aspects of RA. Further, the tariff amendments from that initiative are tied to financial settlement and accounting of slow demand response resources and do not speak to the crediting issue.

Comment: PRR1280 intrudes on state jurisdiction and exceeds CAISO authority.
CAISO Response: The PRR relates to aspects of the RA program that are within the CAISO's tariff authority. LRAs may set their planning reserve margin and establish qualifying capacity methodologies. Nothing about PRR1280 intrudes on LRAs' ability to exercise their authority on those matters.

Comment: PRR1280 is not an appropriate change for a BPM.
CAISO Response: The key outcome of PRR1280 is to ensure consistent treatment of all RA resources under the CAISO tariff and that resources counting towards meeting RA obligations be shown on RA supply plans. This outcome is consistent with existing tariff and as such, the CAISO finds it is an appropriate BPM change.

The CPUC's Energy Division, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company have all pointed out in previous comments that the proposed change lacks the legal authority. It goes beyond the CAISO's legal authority in two ways:

- PRR 1280 exceeds the scope of CAISO Board of Governor's approval of requiring "slow demand response" to be placed on a local reliability supply plan in order for the CAISO to "see" these resources in determining resource sufficiency for the upcoming year.

- PRR 1280 intrudes on and undermines the CPUC's jurisdiction over the RA program; the CPUC as administrator of the RA program, not the CAISO, should control changes in the counting of resources for the upcoming year.

In addition, as discussed in Section II above, the effective elimination of a whole category of resources from compliance eligibility is not a mere implementation detail that should be handled in a BPM change, but a change of material consequence that should be handled through a tariff change submitted to and reviewed by FERC.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, Diablo Canyon Seismic Studies Balancing Account, and Other Activities for the Record Period January 1 Through December 31, 2019. (U 39 E)	Application No. 20-02-009

JOINT MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), THE PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION AND THE JOINT COMMUNITY CHOICE AGGREGATORS FOR ADOPTION OF SETTLEMENT AGREEMENT

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 22, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, Diablo Canyon Seismic Studies Balancing Account, and Other Activities for the Record Period January 1 Through December 31, 2019. (U 39 E)	Application No. 20-02-009

JOINT MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), THE PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION AND THE JOINT COMMUNITY CHOICE AGGREGATORS FOR ADOPTION OF SETTLEMENT AGREEMENT

I. INTRODUCTION

In accordance with Rule 12.1 and 1.8(d) of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and the Joint Community Choice Aggregators (Joint CCAs)[1/] (together, the "Settling Parties")[2/] hereby jointly request that the Commission approve the Settlement Agreement among PG&E, Cal Advocates and Joint CCAs, which is attached to this Joint Motion ("Settlement Agreement"). The Settlement Agreement resolves all but two of the disputed issues in Phase I of the proceeding.[3/] PG&E and Joint CCAs will brief the two remaining issues for resolution by a Commission decision.[4/]

1/ The Joint Community Choice Aggregators consist of East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy, Pioneer Community Energy, San José Clean Energy, Silicon Valley Clean Energy, and Sonoma Clean Power

2/ While a party to the proceeding, The Utility Reform Network ("TURN") is not a signatory to this Settlement Agreement. TURN limited its involvement in this proceeding to the PSPS related issues, which will be addressed in a second phase. *See* TURN's February 28, 2020, Motion for Party Status.

3/ The Settlement Agreement does not address any of the issues reserved for consideration in Phase II of this proceeding.

4/ The Settlement Agreement resolves all disputed issues between PG&E and Public Advocates.

II. PROCEDURAL BACKGROUND

On February 28, 2020, PG&E filed its *Application for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, Diablo Canyon Seismic Studies Balancing Account, and Other Activities for the Record Period January 1 through December 31, 2019,* A.20-02-009 (Application). Concurrent with filing the Application, PG&E also served its Prepared Testimony and workpapers, as well as responses to the Master Data Requests (MDRs) propounded by Cal Advocates.

On April 2, 2020, Cal Advocates and the Joint CCAs filed protests to PG&E's application. PG&E filed a reply to the protests on April 13, 2020. Also on April 13, 2020 PG&E filed Supplemental Testimony including: an accounting of the Public Safety Power Shutoff (PSPS) events that occurred in its service territory in 2019 and explanation of how the PSPS events impacted revenue collections, as directed by the Commission in Decision 20-02-047 and an update on additional Portfolio Allocation Balancing Account (PABA) entries for Renewable Portfolio Standard product sales during the record year.

On May 4, 2020, PG&E submitted a summary of the meet and confer session between the Parties addressing the scope and schedule for the proceeding. On May 12, 2020, the Parties participated in a telephonic pre-hearing conference with assigned Administrative Law Judge (ALJ) Elaine Lau.

On June 19, 2020, Commissioner Guzman Aceves issued an Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo).

On July 10, 2020, Cal Advocates and Joint CCAs served their Testimony.

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Office.

On August 21, 2020, PG&E served its Rebuttal Testimony.

On September 14, 2020, PG&E emailed the service list providing the status of settlement discussions identifying issues resolved and issues still requiring evidentiary hearings. The Settling Parties all agreed and informed the Judge Lau that only one day of evidentiary hearings would be required and identified September 25, 2020 as the preferred date for hearings.

On September 22, 2020, the Settling Parties informed ALJ Lau that the Settling Parties agreed to stipulate the entry of exhibits into the record in lieu of holding evidentiary hearings.

On October 2, 2020, a Joint Motion for Entry of Evidence into the record and concurrent Motion of Pacific Gas and Electric Company to Seal the Evidentiary Record were submitted.

On October 9, 2020, PG&E provided Notice of Settlement Conference to the service list pursuant to Commission Rules of Practice and Procedure (Rule) 12.1(b). The Settlement Conference was conducted telephonically on October 19, 2020. Parties participating in the settlement conference included PG&E, Cal Advocates, and Joint CCAs. Cal Advocates has reviewed PG&E's Application, testimony, workpapers, and responses to discovery and concluded that the Commission's final decision in this proceeding should approve all of the relief requested in PG&E's Application, except as expressly provided in the Settlement Agreement. Similarly, the Joint CCAs have reviewed PG&E's Application, testimony, workpapers, and responses to Joint CCAs discovery requests, and conclude that the Commission's final decision in this proceeding should approve all of the relief requested in PG&E's Application, except as expressly provided in the Settlement Agreement, expressly reserved for briefing and resolution by Commission decision, or reserved for consideration in Phase II of this proceeding.

III. SUMMARY OF THE SETTLING PARTIES' LITIGATION POSITIONS

A. PG&E

In its Application, PG&E requested that the Commission find:

- PG&E complied with its Commission-approved Bundled Procurement Plan (BPP) in the areas of fuel procurement, administration of power purchase contracts, greenhouse gas compliance instrument procurement, resource adequacy sales, and least-cost dispatch of electric generation resources.

- PG&E managed its utility-owned generation (UOG) facilities reasonably.
- The record period expenditures in the Diablo Canyon Seismic Studies Balancing Account (DCSSBA), the Green Tariff Shared Renewables Memorandum Account (GTSRMA), and Disadvantaged Communities Single Family Solar Affordable Homes (DAC-SASH) memorandum subaccount (DACSASHMA) were reasonable.
- The record period entries in the Portfolio Allocation Balancing Account (PABA), Energy Resources Recovery Account (ERRA), Green Tariff Shared Renewables Balancing Account (GTSRBA), and DAC-SASH balancing account (DACSASHBA) were consistent with applicable tariffs and Commission directives.
- Revenue requirements totaling $3.996 million for Diablo Canyon seismic study costs, reflecting the actual recorded costs presented in the DCSSBA plus interest, are reasonable and recoverable from customers.

B. Cal Advocates

Cal Advocates made the following recommendations in its July 10, 2020 Testimony, based on its review of PG&E's Application, Prepared Testimony and associated workpapers and discovery responses:

- The Commission should hold a workshop in order to develop and standardize renewable and storage resource reporting requirements.
- There should be a disallowance of $163,208 because PG&E "failed to provide detailed accountability for the 100.14 days of time it took to restore the Pit 5, Unit 4 outage."

- PG&E should provide a progress report in the next ERRA Compliance Filing of its wicket gate replacements at all Pit 5 Powerhouse units once the work has been completed.
- The Commission should revisit PG&E's GHG Procurement Plan in its review of utility Bundled Procurement Plans in the Integrated Resource Planning proceeding.
- There should be a disallowance of $9,300 related to an amount that was incorrectly recorded to the DACSASHBA.

Cal Advocates also stated that PG&E efforts to procure and sell RA in its solicitations were in compliance with the requirements of PG&E's BPP and that PG&E's transactions with SCE, outside of the requirements of the BPP, were reasonable and should be approved.

PG&E's Rebuttal Testimony resolved or agreed with the matters raised by Cal Advocates. PG&E provided data detailing its management of the Pit 5, Unit 4 outage, explained why a progress report on wicket gate replacements was unnecessary, and pointed to PG&E's errata resolving the $9,300 entry to DACSASHBA. PG&E's testimony noted its support for a Commission-led workshop for all three investor-owned utilities to develop consistent renewable and energy storage resource reporting requirements and supported revisiting PG&E's GHG Procurement Plan in the next review of utility BPPs.

C. Joint CCAs

The Joint CCAs testimony raised concerns about data transparency, whether PG&E complied with its BPP Appendix S, whether certain contracts should be assigned new vintage years, and identified $175.4 million in net reductions (excluding interest) to the 2019 PABA balance based on its review of PG&E's Application, Prepared Testimony, workpapers, and data request responses. The Joint CCAs proposed adjustments to PABA included:

a. A $95.3 million adjustment (plus interest) to comply with D.20-02-047 regarding the value of Retained RPS

b. A reduction of $33.6 million to the 2019 PABA balance for "unsupported" measures of retail sales volumes.

c. A reversal of $38.3 million balance in the PCIA Subaccount to prevent double counting of a PCIA revenue shortfall from January 1 to July 1, 2019.

d. An adjustment of $4.5 million in PABA of Unsold RA to Retained RA because PG&E used PCIA-eligible resources to provide replacement RA capacity for ERRA resources unavailable due to planned outages.

e. An addition to PABA for the Retained RA value to PABA for RA capacity in an SCE Local Area that PG&E used to meet its capacity obligations for bundled customers in 2019 but failed to record.

f. A correction of $16.8 million associated with the REC sales with 2018 deliveries incorrectly recorded to the PABA, rather than the ERRA, in 2019.

g. A reduction to PABA of $18.0 million to correcting balancing accounts for CAISO settlements.

h. An adjustment credit of $1.2 million to recognize the interest credits for periods prior to first recording Retained RA and RPS values to the PABA in June 2019

i. An adjustment for incorrect CCA customer vintage assignments.

PG&E's Rebuttal Testimony resolved some of the issues raised by the Joint CCAs. PG&E agreed with the Joint CCAs recommended adjustments "c." through "i." above and made these adjustments to the PABA and other impacted balancing accounts as necessary. After Rebuttal testimony, the outstanding disputed issues between PG&E and Joint CCAs were reduced to:

1. What adjustments to PABA are necessary for Retained RPS pursuant to D.20-02-047;

2. Whether certain amended contracts should be re-vintaged;
3. Whether PG&E's RA solicitations complied with its BPP Appendix S;
4. A proposed reduction of $33.6 million to PABA for "unsupported" measures of retail sales volumes;
5. What data is necessary to provide greater transparency for the Joint CCAs, and
6. How to adjust bills for incorrect CCA customer vintage assignments.

Through settlement negotiations, PG&E and the Joint CCAs were able to resolve issues 3-6 and agreed to reserve issues 1 and 2 to be briefed and resolved through Commission decision.

IV. SUMMARY OF THE SETTLEMENT AGREEMENT

The Settlement Agreement contains seven substantive sections which set forth the Settling Parties resolution of the disputed issues identified in Section III, B and C: (1) Information Required to Support PG&E's Future ERRA Compliance applications; (2) BPP, Appendix S; (3) Incorrect Vintage Assignments; (4) Exhibits/Record; (5) Least Cost Dispatch; (6) Greenhouse Gas Compliance; and (7) Operation of PG&E's Utility Owned Generation

PG&E's commitment to provide additional, specific information requested by the Joint CCAs simultaneous with its ERRA Compliance applications, and its commitment to simplify the presentation of that information, resolved the Joint CCAs concern with transparency of the PG&E data supporting entries to the ERRA, PABA and related balancing accounts for purposes of this proceeding. These commitments are contained in Sections 1.1 through 1.9 of the Settlement Agreement.

In Section 2, PG&E and the Joint CCAs agreed to resolve the Joint CCAs concerns about PG&E's compliance with Appendix S for record year resource adequacy sales governed by Appendix S by agreeing to continue discussing these concerns and to propose revisions to Appendix S if the discussions so require.

In Section 3, PG&E agreed to implement bill credits for customers who were assigned an incorrect vintage, using specified methodologies to calculate bill credits for commercial and industrial CCA customers (3.1) and residential CCA customers (3.2).

PG&E agreed with certain accounting errors identified by the Joint CCAs and has already made adjustments to the PABA to correct those errors. Section 4.1 identifies the Exhibits reflecting these accounting adjustments.

PG&E objected to the admissibility of certain exhibits into the record for this proceeding based on its position that those exhibits were outside the scope of and/or irrelevant to the proceeding. In Section 4.2, PG&E waives its objections to the admissibility of those exhibits for purposes of this proceeding but reserves its right to make admissibility objections to similar information in future proceedings.

PG&E agrees to participate in a joint IOU workshop to develop and standardize renewable and energy storage reporting requirements, as recommended by Cal Advocates, in Section 5.

Section 6 reflects agreement between PG&E and Cal Advocates that the Commission should consider revisions to PG&E's GHG procurement plan in the next Integrated Resource Planning proceeding (6.1) and reflects PG&E's commitment to present certain GHG information in its testimony supporting ERRA compliance applications (6.2).

In Section 7, Cal Advocates withdraws its challenge to the presentation PG&E made in the case supporting the forced outage at Pit 5, Unit 4 during the record year and supports recovery of $163,208 in replacement power costs attributable to this forced outage in the ERRA.

V. THE COMMISSION SHOULD ADOPT THE SETTLEMENT AS REASONABLE IN LIGHT OF THE WHOLE RECORD, CONSISTENT WITH THE LAW AND IN THE PUBLIC INTEREST

A. Legal Standard for Settlements

Commission Rule 12.1(d) sets forth the standard for adoption of settlements:

> The Commission will not approve settlements, whether contested or uncontested, unless the settlement in reasonable in light of the whole record, consistent with law and in the public interest.

The Commission approves settlement agreements based on whether the settlement agreement is just and reasonable as a whole, not based on its individual terms:

> In assessing settlements we consider individual settlement provisions but, in light of strong policy favoring settlements, we do not base our conclusion on whether any single provision is the optimal result. Rather, we determine whether the settlement as a whole produces a just and reasonable outcome.[5/]

Numerous Commission decisions "have endorsed settlements as an 'appropriate method of alternative ratemaking' and express a strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record."[6/] It is long-standing Commission policy to strongly favor settlement.[7/] This policy supports many worthwhile goals, including not only reducing the expense of litigation and conserving scarce Commission resources, but also allowing parties to reduce the risk that litigation will produce unacceptable results.[8/]

B. The Agreement Is Reasonable in Light of the Record as a Whole

The Settling Parties are knowledgeable and experienced regarding the issues in this ERRA Compliance proceeding and represent distinct and affected interests: PG&E, which is responsible for procuring power to serve its customers; Cal Advocates, the Commission's independent ratepayer advocacy office; and Joint CCAs, community-based energy suppliers serving PG&E unbundled customers. The Settling Parties reached agreement after the submission of lengthy testimony, extensive discovery, careful analysis of issues, and settlement discussions. With respect to the overall agreement by the Settling Parties that PG&E's 2019 entries to ERRA, PABA and various balancing accounts are reasonable with the adjustments agreed to by the Settling Parties, nearly all challenges to these entries have been resolved.

The more qualitative, non-monetary issues raised by parties are resolved in the

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5/ D.10-04-033, *mimeo*, p. 9.
6/ *See e.g.*, D.05-10-041, *mimeo*, p. 47; D.15-03-006, *mimeo*, p.6; and D.15-04-006, *mimeo,* p. 8.
7/ D.10-06-038, *mimeo*, p. 38.
8/ D.14-12-040, *mimeo*, p. 15.

Settlement Agreement in a manner acceptable to all parties. As an example, a key issue for the Joint CCAs is transparency. The Settlement Agreement addresses this issue by PG&E's agreeing to provide additional information requested by the Joint CCAs simultaneous with filing its ERRA Compliance applications and to simplify its presentation of that information. Another example, Cal Advocates believes the GHG procurement framework in the BPP should be re-assessed. This is addressed in the Settlement Agreement by PG&E and Cal Advocates agreeing that the GHG procurement framework should be addressed in the next proceeding examining the IOU BPPs. Finally, PG&E felt strongly that its testimony supporting the application demonstrated that PG&E prudently managed the operations of its generation resources during 2019. This issue is addressed in the Settlement Agreement with the agreement of Cal Advocates that PG&E's showing in this case supported the reasonableness of its management of the forced outage at Pit 5, Unit 4.

The fact that PG&E, Cal Advocates, and Joint CCAs were able to find common ground in areas where they originally differed indicates that the Settlement is reasonable in light of the whole record and reflects a reasonable balance of the various interests affected in this proceeding.

C. The Agreement Is Consistent with Law and Prior Commission Decisions

The Settling Parties believe that the terms of the Settlement Agreement comply with all applicable statutes, including the prospective actions that PG&E will take in future ERRA Compliance proceedings. Applicable statutes include Public Utilities Code § 451, which requires that utility rates must be just and reasonable, and Public Utilities Code § 454, which prevents a change in public utility rates unless the Commission finds such an increase justified.[9/] In this case, Cal Advocates and the Joint CCAs have extensively reviewed and audited the information PG&E presented in testimony and discovery responses to conclude that, except as expressly set forth in the Settlement Agreement, PG&E should be granted the relief requested in

[9/] See D.14-01-011, p. 14; D.15-05-015, p. 14.

its Application, apart from the relief related to issues expressly reserved for consideration of Phase II of this proceeding.

Under the Settlement, Agreement, PG&E agrees to undertake several prospective actions.[10/] The Commission has used ERRA Compliance proceedings to address prospective issues, such as the actions addressed in this Settlement Agreement. For example, in D.09-12-002, the Commission directed that, prior to the next ERRA Compliance application, PG&E confer with Cal Advocates regarding PG&E's internal auditing of contract management activities.[11/] In D.11-07-039, the Commission adopted additional prospective requirements regarding internal auditing.[12/] More recently, the Commission approved prospective actions in the settlement of PG&E's 2011 ERRA Compliance application in D.14-01-011, and in PG&E's 2017 ERRA Compliance Application in D.18-02-015. Thus, including prospective actions in the Settlement Agreement is consistent with Commission precedent in previous ERRA Compliance proceedings.[13/]

D. The Agreement Is in the Public Interest

The Settlement Agreement is in the public interest because it conserves Commission resources and the resources of the Settling Parties. But for the Settlement Agreement, which had as its basis the initial agreement to move exhibits into the record in lieu of holding hearings, Cal Advocates, Joint CCAs, and PG&E would have submitted post-hearing briefs regarding all of the disputed issues in this proceeding. This Settlement Agreement resolves all but two of the outstanding issues in a manner the Settling Parties believe is just and reasonable. These two outstanding issues will be briefed by PG&E and the Joint CCAs for resolution by a Commission decision. Furthermore, the Settlement Agreement is consistent with Commission decisions on settlements, which express the strong public policy favoring settlement of disputes if they are fair

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10/ Settlement, Section II, 1.1 and 2.2.
11/ D.09-12-002, OP 3.
12/ D.11-07-039, OP 2-3.
13/ D.14-01-011, p. 14 (prospective remedies consistent with law).

and reasonable in light of the whole record.[14/]

VI. CONCLUSION

The Settling Parties request that the Commission to adopt the Settlement Agreement without modification as reasonable in light of the whole record, consistent with the law and in the public interest. Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, PG&E represents that Cal Advocates and the Joint CCAs have authorized it to sign and tender this Joint Motion on their behalf.

Respectfully Submitted,

By: */s/ Jennifer K. Post*
JENNIFER K. POST

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY
On Behalf of the Settling Parties

Dated: October 22, 2020

[14/] 14-01-011, p. 13.

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

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, Diablo Canyon Seismic Studies Balancing Account, and Other Activities for the Record Period January 1 Through December 31, 2019. (U 39 E)	Application No. 20-02-009

**SETTLEMENT AGREEMENT
AMONG PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), THE PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION AND JOINT COMMUNITY CHOICE AGGREGATORS**

Pacific Gas and Electric Company (PG&E), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), and the Joint Community Choice Aggregators (Joint CCAs)[1/] (collectively, the Settling Parties)[2/] enter into this Settlement Agreement as a compromise of their respective litigation positions to resolve most disputed issues raised in Phase I of the above-captioned proceeding before the California Public Utilities Commission (Commission). The Settling Parties have negotiated the terms and conditions of this Settlement Agreement to resolve all but two remaining disputed issues. The two remaining disputed issues will be briefed for resolution by a Commission decision.[3/] Any undisputed proposals or requests for relief, apart from those addressing issues expressly reserved for consideration in Phase II of

1/ The Joint CCAs include East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy, Pioneer Community Energy, San Jose Clean Energy, Silicon Valley Clean Energy, and Sonoma Clean Power.

2/ While a party to the proceeding, The Utility Reform Network ("TURN") is not a signatory to this Settlement Agreement. TURN limited its involvement in this proceeding to the PSPS related issues, which will be addressed in a second phase. *See* TURN's February 28, 2020, Motion for Party Status.

3/ The Settlement Agreement resolves all disputed issues between PG&E and Public Advocates Office. Only PG&E and Joint CCAs will submit briefs on the remaining disputed issues.

this proceeding within the Commission's August 14, 2020 *Assigned Commissioner's Amended Scoping Memo and Ruling* (Amended Scoping Memo) shall be deemed unopposed by Cal Advocates and the Joint CCAs. The Settling Parties request that the Commission approve those proposals and requested relief as presented.

I. PROCEDURAL HISTORY

On February 28, 2020, PG&E filed its *Application for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, Diablo Canyon Seismic Studies Balancing Account, and Other Activities for the Record Period January 1 through December 31, 2019,* A.20-02-009 (Application). Concurrent with filing the Application, PG&E also served its Prepared Testimony and workpapers, as well as responses to the Master Data Requests (MDRs) propounded by Cal Advocates.

On April 2, 2020, Cal Advocates and the Joint CCAs filed protests to PG&E's application. PG&E filed a reply to the protests on April 13, 2020. Also on April 13, 2020 PG&E filed Supplemental Testimony including an accounting of the Public Safety Power Shutoff (PSPS) events that occurred in its service territory in 2019 and explanation of how the PSPS events impacted revenue collections, as directed by the Commission in Decision 20-02-047 and an update on additional Portfolio Allocation Balancing Account (PABA) entries for Renewable Portfolio Standard product sales during the record year.

On May 4, 2020, PG&E submitted a summary of the meet and confer session among the parties addressing the scope and schedule for the proceeding. On May 12, 2020, the parties participated in a telephonic pre-hearing conference with assigned Administrative Law Judge (ALJ) Elaine Lau.

On June 19, 2020, Commissioner Guzman Aceves issued an Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo).

On July 10, 2020, Cal Advocates and Joint CCAs served their Testimony.

On August 14, 2020, Commissioner Guzman Aceves issued the Amended Scoping Memo establishing a second phase of the ERRA Compliance proceeding to address issues related to PSPS events.

On August 21, 2020, PG&E served its Rebuttal Testimony.

On September 14, 2020, PG&E emailed the service list providing the status of settlement discussions, identifying issues resolved and issues still requiring evidentiary hearings. The Settling Parties all agreed and informed ALJ Lau that only one day of evidentiary hearings would be required and identified September 25, 2020 as the preferred date for hearings.

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On October 9, 2020, PG&E provided Notice of Settlement Conference to the service list pursuant to Commission Rules of Practice and Procedure (Rule) 12.1(b). The Settlement Conference was conducted telephonically on October 19, 2020. Settling Parties participating in the Settlement Conference included PG&E, Public Advocates Office, and Joint CCAs.

Cal Advocates has reviewed PG&E's Application, testimony, workpapers, and responses to Public Advocates Office's discovery and does not object to the relief requested in PG&E's Application, except as expressly provided in this Settlement Agreement. Similarly, the Joint CCAs have reviewed PG&E's Application, testimony, workpapers, and responses to Joint CCAs discovery requests, and conclude that the Commission's final decision in this proceeding should approve all of the relief requested in PG&E's Application, except as expressly provided in this Settlement Agreement, reserved for briefing and Commission decision, or reserved for consideration in Phase II of this proceeding.

II. SETTLEMENT AGREEMENT TERMS AND CONDITIONS

The Settling Parties agree to the following terms and conditions:

1. Information Required to Support PG&E's Future ERRA Compliance Applications

PG&E and the Joint CCAs agree that PG&E's agreement to provide the following information, in addition to the Master Data Request responses, to the Joint CCAs simultaneous with filing its annual ERRA Compliance applications resolves for purposes of this proceeding the Joint CCAs concerns regarding transparency, asserted discrepancies in PG&E's presentation of billed and recorded customer sales revenues and PG&E's compliance with its 2014 Bundled Procurement Plan (BPP).

1.1 Public and confidential workpapers supporting initial testimony, rebuttal testimony, errata, the November update, and any implementing advice letters from the ERRA Forecast case for the record year.

1.2 A reconciliation of the total costs from parts D-H below with the totals recorded to each applicable Portfolio Allocation Balancing Account (PABA) category using the best available data as of January close for the prior year (record year). January close includes the first set of California Independent System Operator (CAISO) Settlement Agreement data for December of the record year that does not include estimates. PG&E will not provide rolling updates of CAISO Settlement Agreement data after January close.

1.3 To support validation of billed usage, PG&E will provide Electric History (EH) sheet data and a walk from billed usage to EH sheet data.

1.4 For each resource for which costs or revenues are recorded during the record year under review:

(1) resource ID
(2) resource name (using consistent naming convention in compliance and forecast)
(3) PG&E log number
(4) technology
(5) capacity (nameplate)
(6) location
(7) contract type
(8) counterparty
(9) contract execution date
(10) contract expiration date
(11) CPUC authorization

(12) commercial operation date
(13) cost recovery mechanism
(14) vintage
(15) ERRA Forecast category/naming convention
(16) RPS eligibility
(17) monthly trade-month costs (or revenues for contract sales) as of January close, identifying:
i. For Utility Owned Generation: GRC-related, fuel, transportation, and other costs
ii. For contracts: energy, capacity, and other costs (or revenue)
(18) monthly trade-month volumes delivered (generation volumes) as of January close.
i. MWh energy
ii. MW capacity for resource adequacy provided at the time of the CPUC Compliance Filing (RA Tracker)
(19) percentage of self-scheduled day ahead awards

1.5 Monthly CAISO Information as follows:

(1) revenue by CAISO charge code and balancing account
(2) costs by CAISO charge code and balancing account
(3) Settlement Agreements by resource

1.6 Retail revenue information for the record year on a monthly basis as follows:

(1) Billed and unbilled revenue for bundled, CCA and direct access customers
(2) Billed retail sales volumes for bundled, CCA and direct access customers

1.7 Sold and unsold Renewable Portfolio Standard (RPS) products by resource and balancing account

1.8 Resource adequacy information as follows:

(1) sold, unsold and retained resource adequacy by resource and balancing account (RA Tracker)
(2) system, local and flex positions for solicitations governed by Appendix S including the data as presented in the attached RA Position Table for (a) each solicitation in which RA for delivery in the record year was offered for sale (b) at the time each solicitation took place
(3) all Tier 1 advice letter filings addressing Operational Constraints, including confidential attachments.

1.9 PG&E agrees to streamline the presentation of the information it has agreed to provide in sections 1.1-1.8.

2. BPP, Appendix S

PG&E and the Joint CCAs agree to engage in discussions about the approach to Resource Adequacy solicitations governed by Appendix S of PG&E's 2014 BPP, and PG&E may propose revisions to Appendix S to the extent PG&E and the Joint CCAs reach agreement requiring revisions during those discussions.

3. Incorrect Vintage Assignments

3.1 PG&E agrees to rebill all commercial and industrial CCA customers assigned an incorrect vintage. The PABA will be automatically updated with the corrected commercial and industrial revenues.

3.2 PG&E agrees to provide a one-time $5 bill credit to 2012 vintage residential CCA customers that had an incorrect PCIA vintage assignment and a one-time $0.50 bill credit to non-2012 vintage residential CCA customers that had an incorrect PCIA vintage assignment. The PABA balance will not be updated to reflect corrected retail customer revenues, as the values are *de minimis*.

4. Exhibits/Record

4.1 PG&E and the Joint CCAs agree that the following Exhibits in the record confirm adjustments PG&E made to the PABA to correct accounting errors identified by the Joint CCAs: PG&E-11-C, PG&E-12-C, JCCAs-22-C, JCCAs-23-C, JCCAs-24-C, JCCAs-25-C, JCCAs-26, JCCAs-27-C.

4.2 PG&E waives its objection to the admission of Exhibits JCCAs-4-C, JCCAs 5-C, JCCAs-7-C, JCCAs-14, JCCAs-18, JCCAs-19 and PG&E-10-C into the record for this proceeding, A.20-02-009, but reserves the right to argue admissibility of similar information in future ERRA compliance proceedings.

5. Least Cost Dispatch

Cal Advocates recommends in its Testimony that the Commission hold a workshop with all three investor-owned utilities present in order to develop and standardize renewable and energy storage resource reporting requirements. PG&E agrees to participate in any such workshop.

6. Greenhouse Gas Compliance

6.1 PG&E and Public Advocates Office agree that the Commission should revisit PG&E's GHG Procurement Plan in its review of utility Bundled Procurement Plans in the next Integrated Resource Planning proceeding (R.20-05-003 or its successor proceedings).

6.2 PG&E agrees to present with initial prepared testimony served in connection with all future ERRA Compliance applications all covered emissions calculations, including RPS adjustments and actual import emissions (or gross import emissions) prior to any RPS adjustments.

7. Operation of PG&E's Utility Owned Generation

Public Advocates Office withdraws its assertion that PG&E failed to provide adequate support for the forced outage during the record period at the Pit 5, Unit 4 hydro facility and does not object to PG&E's requested recovery through the ERRA of the $163,208 of replacement power costs associated with this forced outage.

III. GENERAL PROVISIONS

8.1 In accordance with Rule 12.5, the Settling Parties intend that Commission adoption of this Settlement Agreement will be binding on the Settling Parties, including their legal successors, assigns, partners, members, agents, parent or subsidiary companies, affiliates, officers, directors, and/or employees. Unless the Commission expressly provides otherwise, and except as otherwise expressly provided herein, such adoption does not constitute approval or precedent for any principle or issue in this or any future proceeding.

8.2 The Settling Parties agree that nothing contained in this Settlement Agreement is to be construed as an admission of liability, fault, or improper action by any Party.

8.3 The Settling Parties agree that this Settlement Agreement is subject to approval by the Commission. As soon as practicable after the Settling Parties have signed this Settlement Agreement, the Settling Parties shall jointly file a motion for Commission approval and adoption of the Settlement Agreement. The Settling Parties will furnish such additional information, documents, and/or testimony as the ALJ or the Commission may require in granting the motion adopting this Settlement Agreement.

8.4 The Settling Parties agree to support the Settlement Agreement and use their best efforts to secure Commission approval of the Settlement Agreement in its entirety without modification.

8.5 The Settling Parties agree to recommend that the Commission approve and adopt this Settlement Agreement in its entirety without change.

8.6 The Settling Parties agree that, if the Commission fails to adopt this Settlement Agreement in its entirety and without modification, the Settling Parties shall convene a Settlement Agreement conference within fifteen (15) days thereof to discuss whether they can resolve the issues raised by the Commission's actions. If the Settling Parties cannot mutually agree to resolve the issues raised by the Commission's actions, the Settlement Agreement shall be rescinded, and the Settling Parties shall be released from their obligation to support the Settlement Agreement. Thereafter, the Settling Parties may pursue any action they deem appropriate but agree to cooperate in establishing a procedural schedule.

8.7 The Settling Parties agree to actively and mutually defend the Settlement Agreement if its approval and adoption is opposed by any other party.

8.8 This Settlement Agreement constitutes a final Settlement Agreement of all but two of the issues reviewed by Public Advocates Office and the Joint CCAs in the above-captioned proceeding. The two remaining issues will be briefed for Commission decision. This Settlement Agreement constitutes the Settling Parties' entire Settlement Agreement, which cannot be amended or modified without the express written and signed consent of all the Settling Parties hereto.

IV. MISCELLANEOUS PROVISIONS

9.1 The Settling Parties agree that no signatory to the Settlement Agreement or any employee thereof assumes any personal liability as a result of the Settlement Agreement.

9.2 If any Party fails to perform its respective obligations under the Settlement

Agreement, any other Party may come before the Commission to pursue a remedy including enforcement.

9.3 The provisions of this Settlement Agreement are not severable. If the Commission, or any competent court of jurisdiction, overrules or modifies as legally invalid any material provision of the Settlement Agreement, the Settlement Agreement may be considered rescinded as of the date such ruling or modification becomes final, at the discretion of the Settling Parties.

9.4 The Settling Parties acknowledge and stipulate that they are agreeing to this Settlement Agreement freely, voluntarily, and without any fraud, duress, or undue influence by any other party. Each party states that it has read and fully understands its rights, privileges, and duties under the Settlement Agreement, including each Party's right to discuss the Settlement Agreement with its legal counsel and has exercised those rights, privileges, and duties to the extent deemed necessary.

9.5 In executing this Settlement Agreement, each Party declares and mutually agrees that the terms and conditions are reasonable, consistent with law, and in the public interest.

9.6 No Party has relied, or presently relies, upon any statement, promise, or representation by any other Party, whether oral or written, except as specifically set forth in this Settlement Agreement. Each Party expressly assumes the risk of any mistake of law or fact made by such Party or its authorized representative.

9.7 This Settlement Agreement may be executed in separate counterparts by the different Settling Parties hereto with the same effect as if all Settling Parties had signed one and the same document. All such counterparts shall be deemed to be an original and shall together constitute one and the same Settlement Agreement.

9.8 This Settlement Agreement shall become effective and binding on the Settling Parties as of the date it is approved by the Commission in a final and non-appealable decision.

9.9 This Settlement Agreement shall be governed by the laws of the State of California as to all matters, including but not limited to, matters of validity, construction, effect,

performance, and remedies.

The Settling Parties mutually believe that, based on the terms and conditions stated above, this Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest. The Settling Parties' authorized representatives have duly executed this Settlement Agreement on behalf of the parties they represent.

PACIFIC GAS AND ELECTRIC COMPANY

Robert S. Kenney
/s/ ________________________________
Robert S. Kenney
Vice President, Regulatory & External Affairs

Date: 10/21/20

JOINT COMMUNITY CHOICE AGGREGATORS

/s/ ________________________________
Tim Lindl
Attorney for the Joint CCAs

Date: ____________________

PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION

/s/ ________________________________
Linda Serizawa
Deputy Director, Public Advocates Office

Date: ____________________

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Vice President, Regulatory Affairs

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/s/Linda Serizawa
Linda Serizawa
Deputy Director, Public Advocates Office

Date: 10/20/20

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/s/ ________________________________
Linda Serizawa
Deputy Director, Public Advocates Office

Date: ___________________

JOINT COMMUNITY CHOICE AGGREGATORS

/s/ ________________________________
Tim Lindl
Attorney for the Joint CCAs

Date: October 20, 2020

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

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, Diablo Canyon Seismic Studies Balancing Account, and Other Activities for the Record Period January 1 Through December 31, 2019.	Application No. 20-02-009 (Filed February 28, 2020)

OPENING BRIEF OF THE JOINT COMMUNITY CHOICE AGGREGATORS

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October 26, 2020

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, Diablo Canyon Seismic Studies Balancing Account, and Other Activities for the Record Period January 1 Through December 31, 2019.	Application No. 20-02-009 (Filed February 28, 2020)

OPENING BRIEF OF THE JOINT COMMUNITY CHOICE AGGREGATORS

East Bay Community Energy ("EBCE"),[1] Marin Clean Energy ("MCE"),[2] Peninsula Clean Energy Authority ("PCE"),[3] Pioneer Community Energy ("Pioneer"),[4] San José Clean Energy ("SJCE"),[5] Silicon Valley Clean Energy Authority ("SVCE"),[6] and Sonoma Clean Power Authority ("SCP")[7] (collectively "the Joint CCAs") hereby submit this Opening Brief in opposition to the *Application of Pacific Gas and Electric Company ("PG&E") for Compliance*

1 EBCE is the community choice aggregator ("CCA") serving Alameda County.

2 MCE is the CCA serving Marin County, unincorporated Napa County, unincorporated Contra Costa County, unincorporated Solano County, and the Cities and Towns of American Canyon, Calistoga, Napa, St. Helena, Yountville, Benicia, Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Richmond, San Pablo, San Ramon, and Walnut Creek.

3 PCE is the CCA serving San Mateo County.

4 Pioneer is the CCA serving unincorporated Placer County, the Cities of Auburn, Colfax, Lincoln, and Rocklin, and the Town of Loomis.

5 SJCE is the CCA serving the City of San José.

6 SVCE is the CCA serving unincorporated Santa Clara County, and the Cities and Towns of Campbell, Cupertino, Gilroy, Los Altos, Los Altos Hills, Los Gatos, Milpitas, Monte Sereno, Morgan Hill, Mountain View, Saratoga, and Sunnyvale.

7 SCP is the CCA serving the Cities of Cloverdale, Cotati, Fort Bragg, Petaluma, Point Arena, Rohnert Park, Santa Rosa, Sebastopol, Sonoma, Willits and the Town of Windsor, and the Counties of Sonoma and Mendocino.

Review of Utility Owned Generation ("UOG") Operations, Portfolio Allocation Balancing Account ("PABA") Entries, Energy Resource Recovery Account ("ERRA") Entries, Contract Administration, Economic Dispatch of Electric Resources, UOG Fuel Procurement, Diablo Canyon Seismic Studies Balancing Account, and Other Activities for the Record Period January 1 Through December 31, 2019 ("Application").

The Joint CCAs' testimony raised numerous issues in this proceeding based on a review of PG&E's Application, Prepared Testimony, workpapers, and data request responses, including identifying $175.4 million in net reductions (excluding interest) to the 2019 PABA balance. The Joint CCAs also addressed data transparency, whether PG&E complied with its Bundled Procurement Plan, Appendix S, and whether certain contracts should be assigned new vintage years. PG&E's rebuttal testimony in this proceeding, combined with the settlement agreement and joint motion filed on October 22, 2020, have resolved all but two of these issues.[8]

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[8] Issues raised by the Joint CCAs that were resolved by PG&E's reply testimony include: 1) the reversal of the $38.3 million balance in the PCIA Subaccount to prevent double counting of PCIA revenue shortfall from January 1 to July 1, 2019; 2) an adjustment of $4.5 million in the PABA of Unsold RA to Retained RA because PG&E used PCIA-eligible resources to provide replacement RA capacity for ERRA resources unavailable due to planned outages; 3) an addition to the PABA for the Retained RA value to the PABA for RA capacity in an SCE Local Area that PG&E used to meet its capacity obligations for bundled customers in 2019 but failed to record; 4) a correction of $16.8 million associated with the REC sales with 2018 deliveries incorrectly recorded to the PABA, rather than the ERRA, in 2019; 5) a reduction to PABA of $18.0 million to correct balancing accounts for CAISO settlements; 6) an adjustment credit of $1.2 million to recognize the interest credits for periods prior to first recording Retained RA and RPS values to the PABA in June 2019; and 7) an adjustment for incorrect CCA customer vintage assignments. *See* Joint Motion of Pacific Gas and Electric Company (U 39 E), the Public Advocates Office at the California Public Utilities Commission and the Joint Community Choice Aggregators for Adoption of Settlement Agreement at pp. 5-6 (October 22, 2020). Issues raised by the Joint CCAs that are resolved in the settlement include: 1) whether PG&E's RA solicitations complied with its BPP Appendix S; 2) a proposed reduction of $33.6 million to the PABA for "unsupported" measures of retail sales volumes; 3) data necessary to provide greater transparency; and 4) mechanisms for making bill adjustments for incorrect CCA customer vintage assignments. *See id.* at pp. 6-7.

The remaining disputed issues relate to Issue 3 identified in Commissioner Guzman Aceves's August 14, 2020 Amended Scoping Ruling:[9]

> Issue 3. Whether the entries recorded in the Energy Resource Recovery Account (ERRA) and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate, and in compliance with Commission decisions.

These issues are (1) the request in PG&E's rebuttal testimony to reverse the $92.9 million adjustment it belatedly made in response to D.20-02-047 to its PABA regarding the amount of Renewable Portfolio Standard ("RPS") energy the utility retained to serve its bundled customers in 2019; and (2) the utility's decision not to re-vintage four RPS contracts renegotiated during 2019.

Both of these components of PG&E's Application and testimony are unreasonable, inappropriate, inaccurate, and in contravention of Commission decisions. First, in D.20-02-047, the Commission ordered PG&E to adjust the PABA to increase the RPS value therein by $92.9 million.[10] PG&E disagreed with the Commission's decision and filed for rehearing.[11] The utility misled the Commission in that Application for Rehearing, stating it "has already reversed the $92.9 million PABA entry as directed by the Decision,"[12] when in fact the utility only made a $69.3 million adjustment to the PABA.[13] The utility did not make the $92.9 million adjustment

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[9] A.20-02-009, *Assigned Commissioner's Amended Scoping Memo and Ruling*, p. 3 (August 14, 2020) ("Amended Scoping Ruling").

[10] *See* D.20-02-047, pp. 13-16 and Conclusion of Law 4 (February 27, 2020); JCCAs-1 10:2-4.

[11] Exh. PGE-4 at Attachment A.

[12] *Id*. at Ch. 12, Attachment A, p. 12-AtchA-6. *See also id*. at p. 12-AtchA-5 ("PG&E accepts the deduction of $92.9 million from the Portfolio Allocation Balancing Account ("PABA") required by the Decision and does not seek to reverse the decision or use a different amount at this time. Instead, PG&E's rehearing application aims to ensure compliant implementation of the Decision going forward…").

[13] *See* Exh. PGE-2 at 2-3:27-29; Exh. PGE-4 at 12-3:19-21; Exh. PGE Exh. JCCAs-23-C.

until August 2020, approximately six months after D.20-02-047 was issued, in response to the Joint CCAs' Direct Testimony in this proceeding.[14]

PG&E now requests to reverse that adjustment back to $69.3 million, suggesting the utility's methodology is correct and the methodologies in D.20-02-047 are incorrect. PG&E's proposal cannot be "in compliance with Commission decisions" when it is premised on reversing such decisions. As demonstrated in detail below, PG&E is wrong on both the process and the substance on this issue and wastes the Commission and stakeholders' time and resources in seeking a third "bite of the apple."

Second, PG&E should have re-assigned the vintage year of four power purchase agreements ("PPAs") for generation resources the prices of which PG&E renegotiated and materially modified in 2019. Such re-assignment ensures customers departing prior to major contract renegotiation are not responsible for procurement costs associated with resource commitments made after they have departed, consistent with the cost-responsibility principles established first in Decision 04-12-048 and later applied to the PCIA framework in Decision 18-10-019.[15] It is appropriate for the Commission to decide the vintaging of these contracts in this ERRA compliance proceeding where PG&E's customers affected by the PABA are represented, and where the Commission has the opportunity to address and directly resolve *all* of the tens of contracts PG&E amends each year.

Therefore, PG&E's request to reverse the $92.9 million PABA entry and its failure to re-vintage the renegotiated contracts are unreasonable. Instead, the Commission should:

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[14] JCCAs-1 at i, 8:8 to 14:18; Exh. PGE-4 at 12-3:19-21; Exh. PGE Exh. JCCAs-23-C.

[15] *See* R.04-04-003, *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company's Long-Term Procurement Plans*, p. 55 (December 20, 2004) ("D.04-12-048"); R.17-06-026, *Decision Modifying the Power Charge Indifference Adjustment Methodology,* p. 3 (October 11, 2018) ("D.18-10-019").

- Reject PG&E's request to reverse its $92.9 million adjustment and order the utility to adjust the PABA by $2.4 million, plus interest, to reflect the actual $95.3 million value of retained RPS; and

- Order PG&E to re-vintage the four renegotiated PPAs as 2019-vintage contracts.

Both of these issues are addressed in detail below.

I. LEGAL STANDARD

The magnitude of the impact of PG&E's application on both departed and bundled customers requires cautious and careful consideration under the applicable standards of proof. PG&E, as the applicant, has the burden of affirmatively establishing the reasonableness of all aspects of its application,[16] and that burden of proof generally is measured based upon a preponderance of the evidence.[17]

The Commission cannot grant the relief requested in PG&E's Application without substantial evidence to support the rates requested therein.[18] California courts will overturn Commission decisions that lack substantial evidence.[19] Mere rubber-stamping of uncorroborated, disputed evidence does not meet this standard.[20] The Commission, therefore, must require PG&E to support its assertions with sufficient evidence or reject the components of PG&E's Application unsupported by substantial evidence.

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16 R.11-02-019, *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering,* p. 42 (December 28, 2012) ("D.12-12-030").

17 *See, e.g.,* A.17-06-005, *Decision Adopting Pacific Gas and Electric Company's 2018 Energy Resource Recovery Account Forecast and Generation Non-Bypassable Charges and Greenhouse Gas Forecast Revenue and Reconciliation*, pp. 9-10 (January 16, 2018) ("D.18-01-009"); R.11-02-019, *Order Modifying Decision (D.) 12-12-030 and Denying Rehearing, as Modified,* p. 29 (July 27, 2015) ("D.15-07-044") (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.").

18 Cal. Pub. Util. Code § 1757(a)(4). *See, e.g., The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (February 5, 2014).

19 Cal. Pub. Util. Code § 1757(a)(4). *See, e.g., The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 958-9 (February 5, 2014).

20 *See id*.

Further, the entries PG&E recorded to the ERRA and PABA must be reasonable, appropriate, accurate, and in compliance with Commission decisions.[21]

Finally, the Public Utilities Code gives conclusive effect to all Commission decisions once they are final.[22] The legislature has accordingly limited the methods that parties may use to attack Commission decisions, making collateral attacks illegal.[23] As the Commission set forth in Decision 14-02-016, "[a]ny challenge [to a Commission decision] must be 'direct' (as opposed to collateral), and must be made within statutory time limits, after properly exhausting administrative remedies."[24] A utility cannot avoid the effect of a Commission decision by repeatedly challenging the same issue resolved by that decision.[25] Such an outcome is illegal, fundamentally prejudices parties appearing before the Commission who do not have cost recovery guaranteed for their litigation costs, and undermines the Commission's oversight of PG&E. Each of these reasons supports a Commission decision ordering PG&E to take the actions required by D.19-10-001 and D.20-02-047.

PG&E's proposal regarding retained RPS in this proceeding not only fails to follow D.19-10-001 and D.20-02-047, it does not meet the statutory requirements for challenging a Commission decision and instead mounts an impermissible collateral attack on both decisions. Further, PG&E's failure to re-vintage four renegotiated PPAs does not follow Commission decisions, rules and policy established in D.04-12-048, D.05-01-031, D.08-09-012, Resolution E-484, and Resolution E-5905.

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21 *See, e.g.*, Amended Scoping Ruling at 3.

22 A. 13-06-015, *Order Modifying D.14-02-016 and Denying Rehearing of the Decision, As Modified*, p. 13 ("D.14-06-053") (June 26, 2014) (citing D.14-02-016; Cal. Pub. Util. Code, §§ 1708, 1709, 1731(b)(1), 1756, 1757, 1759).

23 *Id.* at 14.

24 *Id.* (citation omitted).

25 *See id.* at 14-15.

II. BACKGROUND ON THE ERRA COMPLIANCE PROCEEDING, THE PCIA AND THE PABA

While ERRA compliance proceedings have occurred for many years, this particular proceeding is unique because it constitutes the last step in implementing the Commission's revised framework for calculating the PCIA.[26] The PCIA constitutes the above-market costs of certain resources in the utility's generation portfolio, *i.e.*, the difference between the costs of that portfolio and the market value of that portfolio.[27]

In 2018, and again in 2019, the Commission revised the PCIA to add a true-up.[28] Prior to then, the PCIA rate was set only on a forecasted basis for CCA customers.[29] That is, only a forecast of PG&E's generation costs and revenues mattered when setting the rate—PG&E's *actual* generation costs and revenues never entered the equation and the PCIA rate was not revisited after it was set initially.[30] The 2018 and 2019 decisions (D.18-10-019 and D.19-10-001) incorporated a comparison of the forecasted costs and revenues in PG&E's portfolio with the actual costs and revenues PG&E records during the target year so that the PCIA rate will be trued up in the same way as the ERRA portion of the bundled generation rate is trued up.[31]

That comparison of actual costs and revenues occurs via the PABA.[32] The PABA balance at the end of the target year comprises one of two major components of PCIA rates for the following year, with the second being the forecast of above-market costs in that following year.[33] This ERRA compliance proceeding is the first time the Commission will assess

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26 Exh. JCCAs-1 at i.
27 *Id.*
28 *Id.*
29 *Id.*
30 *Id.*
31 *Id.*
32 *Id.*
33 *Id.*

"[w]hether the entries recorded in the . . . Portfolio Allocation Balancing Account are reasonable, appropriate, accurate, and in compliance with Commission decisions."[34] The target year for this analysis is 2019, and adjustments made to the PABA as part of this proceeding will impact the PCIA rates unbundled customers pay going forward.[35]

III. SETTING PG&E'S RECORDED RETAINED RPS VALUES AT $69.3 MILLION WOULD VIOLATE D.19-10-001 AND D.20-02-047.

PG&E's entries in the 2019 PABA to reflect the RPS energy the utility retained to serve its bundled customers contravene D.19-10-001 and D.20-02-047 and are otherwise unreasonable, inappropriate, and inaccurate. In February of this year, the Commission issued D.20-02-047 setting the quantity of Retained RPS in the utility's portfolio for 2019 equal to PG&E's expected 2019 compliance target of 11,252 GWh, which eliminated all Unsold RPS for that year for PG&E.[36] The Commission ordered a corresponding adjustment to increase RPS value in the PABA by $92.9 million, which was the result of adjusting Retained RPS to the forecasted 2019 compliance target.[37] A $95.3 million adjustment to the PABA results from updating the $92.9 million figure, which was comprised of nine months of actual sales data and a forecast of three months of sales data, to reflect the actual quantities experienced during the full 12-month period.[38]

Rather than follow the requirements the Commission set forth in D.20-02-047, PG&E flouted the decision and made a $69.3 million adjustment to the PABA in March 2020.[39] PG&E also misled the Commission in its March 30, 2020 Application for Rehearing, where it stated it

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34 A.20-02-009, *Assigned Commissioner's Scoping Memo and Ruling*, p. 3 (June 19, 2020) ("Scoping Ruling").

35 Exh. JCCAs-1 at i.

36 D.20-02-047, pp. 13-16 (February 27, 2020).

37 *See id*., pp. 13-16 and Conclusion of Law 4 (February 27, 2020); Exh. JCCAs-1 10:2-4.

38 Exh. JCCAs-1 at 12:24-27, to 13:14 to 14:3.

39 *See* Exh. PGE-2 at 2-3:27-29; Exh. PGE-4 at 12-3:19-21; Exh. PGE Exh. JCCAs-23-C.

"has already reversed the $92.9 million PABA entry as directed by the Decision."[40] In fact, the utility did not make the adjustment until approximately six months after D.20-02-047 was issued, and only agreed to make the belated $92.9 million adjustment in August 2020 in response to the Joint CCAs' Direct Testimony in this proceeding.[41]

Despite making the $92.9 million adjustment in August, PG&E's rebuttal testimony continues the utility's impermissible collateral attack on both D.19-10-001 and D.20-02-047, suggesting the Commission (1) made a mistake in the latter decision, (2) should overturn that decision in this proceeding in contravention to the framework laid out in D.19-10-001, and (3) allow the utility to change its $92.9 million adjustment in August back to the $69.3 million adjustment it originally made in March.[42]

Not only should the Commission reject this request, it should make clear that it will not tolerate re-litigation of issues decided in an ERRA Forecast case within the following ERRA Compliance case. Granting PG&E's request to revise D.20-02-047 as part of this proceeding would establish troubling precedent requiring the Commission and stakeholders to litigate the same set of facts over and over – indeed, this brief represents the third of four times the Commission and parties will be required to address this issue, (1) having already addressed it in A.19-06-001, (2) addressing it in response to PG&E's Application for Rehearing of D.20-02-047, (3) addressing it here, and (4) having to address it in A.20-02-007, PG&E's 2021 ERRA Forecast case, in which PG&E, bewilderingly, raised this issue *yet again*.[43]

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40 Exh. PGE-4 at Ch.12, Attachment A, p. 12-AtchA-6.

41 Exh. JCCAs-1 at i, 8:8 to 14:18; Exh. PGE-4 at 12-3:19-21; Exh. PGE Exh. JCCAs-23-C.

42 Exh. PGE-4 at 12-3:22 to 12-7:14.

43 D.20-02-047 at 13-16; Exh. PGE-4 at Ch. 12, Attachment A; and A.20-02-007, *Pacific Gas and Electric Company Prepared Testimony 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*, 14-12:1-9 (July 1, 2020).

The fact is the Commission already decided the issues PG&E is raising in this case as part of its disposition of A.19-06-001 while relying on the framework adopted in R.17-06-026. Complying with both resulting decisions, D.20-02-047 and D.19-10-001, and ensuring PG&E's 2019 recorded PABA amounts are reasonable, appropriate, and accurate, requires PG&E to record a $95.3 million adjustment, plus interest retroactive through 2019.

A. PG&E's Recommendation Does Not Follow D.19-10-001 and D.20-02-047 and Constitutes an Impermissible Collateral Attack on Both Decisions.

In the wake of D.18-10-019, Decision 19-10-001 further refined the Commission's methodology to true up forecasted values with actual values in the PABA, including establishing a framework to true up the value of RPS products.[44] Actual RPS value in the PABA true up is calculated for three categories: Actual Retained, Actual Sold, and Actual Unsold.[45] Actual Retained RPS volumes are those volumes used for IOU compliance from PG&E's PCIA-eligible portfolio.[46] Actual Sold RPS volumes are those volumes sold in 2019, and Actual Unsold are those volumes PG&E was unable to sell in 2019.[47] The values and quantities to be used for each category are shown in Figure 1 from the Joint CCAs' testimony, which reproduces Table III from Appendix B of D.19-10-001.[48]

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44 Exh. JCCAs-1 at 8:14-16.
45 *Id.* at 8:16 to 9:3.
46 *Id.*
47 *Id.* at 9:3-4.
48 D.19-10-001 Attachment B at 2 Table III; *see also id.* at 56, Ordering Paragraph 4 (directing that the utilities shall follow Attachment B Table III).

Figure 1: PABA Framework for RPS Value

Table III: RPS Value True Up (Price and Quantity)

Type of RPS Product	**Price**	**Quantity**
Actual Retained	Final RPS Adder, as calculated by Staff	Volume used for IOU compliance from PCIA-eligible portfolio
Actual Sold	Actual transacted price s	Actual transacted volumes
Actual Unsold	$0	Actual unsold volume

A key question in A.19-06-001 was what quantity of RPS generation should be classified as Actual Retained RPS, *i.e.*, the "volume used for IOU compliance" in the second row in Figure 1.[49] The Commission determined in D.20-02-047 Conclusion of Law 4 that "D.19-10-001 requires PG&E to value all renewable energy credits used to meet its 2019 compliance obligation at the RPS Adder."[50] That is, the annual RPS compliance targets provided in D.11-12-020 are the "appropriate minimum quantity to be considered retained for purposes of the PABA true-up."[51] In doing so, the Commission set the volume of Retained RPS equal to PG&E's forecasted 2019 compliance target of 11,252 GWh, which eliminated all Unsold RPS for 2019, and required a corresponding adjustment to increase RPS value in the PABA by $92.9 million, which was the result of adjusting Retained RPS to the forecasted 2019 compliance target.[52] The Commission already conclusively decided the question PG&E raises here.

PG&E's rebuttal testimony blames the Commission for what the utility incorrectly believes is an inadvertent error in D.20-02-047, laying bare the fact that PG&E is using this case

[49] Exh. JCCAs-1 at 11-2.
[50] D.20-02-047 at COL 4.
[51] *Id*. at 14 (February 27, 2020). The Commission also found that "PG&E should not use banked RECs to increase its REC generation for a given year beyond its compliance and sales commitments" and that "the 20% of starting bank RECs included in PG&E AL 5554-E should not be counted as unsold RPS." *Id*. at 15-16.
[52] D.20-02-047, pp. 13-16 (February 27, 2020); Exh. JCCAs-1 at 9:25 to 10:1.

to improperly challenge D.20-02-047.[53] If PG&E believed the Commission committed an inadvertent error in D.20-02-047, PG&E should have included a request in its March 30, 2020 Application for Rehearing that the Commission revise the findings made in D.20-02-047 to instead require a different adjustment to the RPS value in the PABA. Instead, tellingly, PG&E expressly "[accepted] the deduction of $92.9 million from the [PABA] required by the Decision and [did] not seek to reverse the decision or use a different amount at this time."[54] PG&E then filed Advice Letter 5781-E, establishing PCIA rates for 2020 that included the $92.9 million reduction approved in D.20-02-047.[55] Problematically, however, PG&E did not in fact record the $92.9 million adjustment to the PABA. Instead, in March 2020 PG&E only made a $69.3 million adjustment to the PABA.[56] PG&E now requests in this docket the relief it could have requested in its March 30, 2020 Application for Rehearing in A.19-06-001, but expressly chose not to request at that time.[57] As a result, PG&E's current request constitutes an impermissible, indirect challenge to the Commission's decision in A.19-06-001.[58] On this procedural basis alone, the Commission should reject PG&E's request to reinstate its $69.3 million adjustment.

However, not only does PG&E have the process wrong in this case, it also has the substance wrong. PG&E incorrectly argues – both in its Application for Rehearing and in its Supplemental and Rebuttal Testimony in this case – that D.20-02-047 is limited solely to a single conclusion, *i.e.*, PG&E's use of banked RECs to increase Unsold RPS by 4,213 GWh, which,

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53 Exh. PGE-4 at 12-4:27.

54 *Id.* at Ch. 12, Attachment A, p.12-AtchA-5. Notably, PG&E's limited request for relief in the Application for Rehearing prevents the Commission from authorizing "PG&E to correct the $92.9 million adjustment to $69.3 million … in its decision on PG&E's Application for Rehearing," as suggested by PG&E's Rebuttal Testimony. *Id.* at 12-17:10-12.

55 JCCAs-1 at 3-4.

56 *See* Exh. PGE-2 at 2-3:27-29; Exh. PGE-4 at 12-3:19-21; Exh. PGE Exh. JCCAs-23-C.

57 *See* Exh. PG&E-4 at Ch. 12, Attachment A, p.12-AtchA-5.

58 *See* D.14-06-053 at 13-14 (citing D.14-02-016; Cal. Pub. Util. Code, §§ 1708, 1709, 1731(b)(1), 1756, 1757, 1759) (collateral attacks impermissible).

when multiplied by 2019 RPS Adder, would equal $69.3 million.[59] In making this argument, PG&E fails to account for the other elements of the decision.

In addition to Conclusion of Law 4 discussed above, D.20-02-047 states "PG&E should not use banked RECs to increase its REC generation for a given year beyond its compliance and sales commitments."[60] This conclusion is equally as important as the conclusion PG&E chooses to focus on. The Decision rightly ensures the Unsold RPS is not used to reduce the quantity of Retained RPS below the annual RPS compliance target, which would result in understating the value of the Retained RPS recorded to the PABA. PG&E's testimony in this case and in its Application for Rehearing improperly disregards this conclusion to focus solely on the 4,213 GWh of Unsold RPS.

PG&E's real quibble may be that its decision to oversell its 2019 RPS generation, *i.e.*, to sell more than its excess RPS, or to successfully sell itself short in its RPS solicitations,[61] results in an oddity under D.19-10-001's framework. Essentially, PG&E's decision results in the utility having what might be termed "negative Unsold RECs." The cause of this oddity is the non-2019 banked RECs PG&E will need to use for compliance. That is, the negative unsold REC position is created by PG&E selling more than its Excess RPS on the assumption it will use non-2019 banked RECs to fill the gap.

However, the Commission's decision recognizes this issue, as well, including the problems it may cause under D.19-10-001's framework when utilities sell more than their Excess RPS. D.20-02-047 correctly identifies the underlying problem that "[u]nder the current PABA framework, it cannot be determined whether retired RECs in PABA were 'unsold' or 'retained

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59 *See, e.g.,* Exh. PG&E-4 at 12-4:3-19 and Ch. 12, Attachment A, p.12-AtchA-10 to 11; Exh. Joint CCAs-1 at 10:18-20.
60 *Id.* at 15.
61 Exh. PG&E-4 at Ch. 12, Attachment A, p.12-AtchA-11.

for compliance.'"[62] The decision suggests "[a] tracking framework within PABA and mechanisms to value banked RECs at the end of the compliance period may help resolve these issues."[63] Finally, it concludes that "[t]hese issues are however, more appropriately addressed by the Commission in the PCIA proceeding."[64] In other words, the Commission determines the oddity of negative Unsold RPS that results from PG&E's decision to oversell its RPS may be cause for further consideration of the D.19-10-001 framework within the PCIA docket.

PG&E cannot simply read this conclusion or Conclusion of Law 4 out of the decision and assert the Commission erred in failing to follow its own methodology. It also cannot seek to relitigate the findings of D.19-10-001 and D.20-02-047 in the instant proceeding. The bottom line is that PG&E is arguing against the Commission's previously established framework for determining the volume used for RPS compliance each year in D.19-10-001 and the Commission's implementation of that framework in D.20-02-027. It is not possible for PG&E to meet the standard in this proceeding for its proposals to be "in compliance with Commission decisions"[65] if those proposals rely on the Commission determining its prior decisions were wrong in the first place.

B. The Recorded PABA Balance for 2019 Should be Adjusted to Reflect the Most Accurate Data Available.

Finally, the $92.9 million figure from D.20-02-047 was calculated based on partially forecasted quantities of RPS generation, the amount of Retained RPS, and PG&E's 2019 compliance target and should be revised to an adjustment of $95.3 million.[66] The compliance target relied on in D.20-02-047 comprised nine months of actual sales data (from January to

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62 D.20-02-047 at 15.
63 *Id.*
64 *Id.* at 15-16.
65 Amended Scoping Ruling at 3.
66 Exh. JCCAs-1 at 12:22-24.

September) and a forecast of three months of sales data (October to December), due to the timing of the November Update.[67] The final PABA balance for 2019, however, should reflect the actual quantities experienced during the full 12-month period.[68]

While the utility takes issue with the Commission's methodology, as described in the prior section, "PG&E agrees that 2019 actuals should be used."[69] In its response to Joint CCAs DR 6.09, PG&E confirmed that the total actual bundled retail sales for 2019 were 35,956 GWh, and this value "will be used as part of the calculation for the Procurement Quantity Requirement for Compliance Period 3 (2017-2020)," *i.e.*, PG&E's RPS compliance target for 2019.[70] Multiplying 35,956 GWh by the 31% compliance target for 2019 equates to 11,146 GWh of Retained RPS.[71]

Consistent with D.20-02-047 and D.19-10-001, the actual RPS volumes and the actual compliance target should be used to determine the value of Actual Retained RPS energy in PG&E's portfolio during 2019.[72] Table 3 in the Joint CCAs direct testimony demonstrates that a credit of $95.3 million is required to correct the recorded PABA balance to comply with D.20-02-047 and reflect Actual Retained RPS at PG&E's actual RPS compliance target for 2019.[73] Here again, PG&E's Rebuttal Testimony does not dispute this calculation, but instead takes issue with the Commission's methodology.[74]

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67 *Id*. at 12:24-27.
68 *Id*. at 12:27 to 13:1.
69 Exh. PGE-4 at 12-6:15.
70 Exh. JCCAs-1 at 13:3-6.
71 *Id*. at 13:6-7. Actual Retained and Sold RPS are also now available for all twelve months of 2019. *Id*. at 13:9-10.
72 *Id*. at 13:10-12.
73 *Id*. at 13:12 to 14:3 and p. 13, Table 3.
74 Exh. PGE-4 at 12-6:15-20.

Updating the $92.9 million adjustment to $95.3 million, plus interest, aligns with the Commission's policy framework for the PABA and PCIA.[75] The Commission's aim in implementing the true-up is to determine a more accurate assessment of the value of PG&E's portfolio in a given year, replacing forecasted values with actual values.[76] The $95.3 million value for Actual Retained RPS meets this goal by using the utility's actual retail sales volumes and, in turn, its actual RPS compliance target for 2019.[77] In contrast, the $92.9 million figure was based on three months of forecasted values, rather than actual values, and falls short of the Commission's goals.[78] PG&E should be required to modify its adjusting entry reducing the PABA balance to $95.3 million, rather than its proposed $69.3 million adjustment, plus interest retroactive to the beginning of 2019.[79]

IV. PG&E SHOULD HAVE REASSIGNED FOUR RENEGOTIATED GENERATION CONTRACTS TO THE 2019 VINTAGE.

PG&E should have re-assigned the vintage year of four contracts for generation resources that were renegotiated and materially modified in 2019. A key tenet of the Commission's PCIA framework is that when customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[80] Departed customers are not responsible for procurement costs associated with resource commitments made after they have departed. To effectuate this policy in the context of renegotiated contracts, the

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75 Exh. JCCAs-1 at 14:5-7.
76 *Id*. at 14:7-9.
77 *Id*. at 14:9-11.
78 *Id*. at 14:11-12.
79 *Id*. at 14:14-18.
80 D.18-10-019 at 3; *see also* R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (September 25, 2017).

Commission has indicated that a contract should be assigned a new vintage year when the utility modifies material terms of a resource generation contract.

In the 2019 record period, PG&E chose to renegotiate and amend the price terms of four contracts for generation resources. Because price is a material term, the amended contracts should now be assigned a 2019 vintage under cost-recovery principles adopted by the Commission, as addressed below.

It is appropriate for the Commission to decide the vintaging of these contracts in this ERRA compliance proceeding where PG&E's customers affected by the PABA are represented, and where the Commission has the opportunity to address and directly resolve *all* of the tens of contracts PG&E amends each year. These issues are discussed in more detail in the following sections.

A. PG&E Renegotiated and Materially Modified the Contracts and Should Have Reassigned Them to the 2019 Vintage.

The vintaging of a contract turns on when the utility made the contractual ***commitment*** and relatedly when utility customers have departed for purposes of determining "responsibility" for causing the utility to enter into the contractual commitments. Decision 04-12-048 explained that a CCA customer would be responsible for certain costs until the IOU's responsibility to plan on behalf of that CCA customer ends.[81] According to the Commission, "[t]he law permits the recovery of stranded costs from those customers who are responsible for stranded costs related to resource and contractual commitments made by the IOU up until the time of the customer's departure and…departing customers should bear no cost responsibility for such commitments the IOU makes after their departure."[82] Pursuant to D.08-09-012, in order "[t]o implement the

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81 *See* D.04-12-048 at 55.

82 R.06-02-013, *Decision on Non-Bypassable Charges for New World Generation and Related Issues*, p. 59 (September 5, 2008) ("D.08-09-012").

stranded cost recovery principles adopted in D.04-12-048, the IOUs must track the generation costs, including the costs of certain generation commitments, incurred to serve departing customers up to the point when a particular customer departs and the IOU no longer provides procurement services to serve its load."[83]

The core principle of vintaging is thus to identify when a "commitment" is made or renegotiated for a resource so that customers may be assigned responsibility for that resource.[84] Departed customers will not be responsible for "commitments the IOU makes *after* their departure."[85] In this regard, the Commission has determined, with respect to power purchase agreements, that a resource "commitment" is made in relation to the execution and effectiveness of the underlying contract.[86]

With respect to cost responsibility, two factors should be considered. First, the Commission should examine whether the underlying contract was "renegotiated." According to the Commission, "the circumstances by which the terms of the [resource] contracts were changed" are chiefly important in determining cost responsibility.[87] The Commission reached this conclusion in reviewing similar cost responsibility matters.[88] In D.05-01-031, the Commission implicitly acknowledged that changes to contracts that are "the result of a 'buy-out,

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83 *Id*. at 59.

84 *See id*. at 65, note 63.

85 *See id*. at 59 (emphasis added). *See also* D.08-09-012 at 65, note 63 (emphasis added) ("We agree with SCE's statement that 'Ideally, departing customers should bear no cost responsibility for the resource and *contractual commitments* SCE makes after their departure.'") and D.11-12-018 at 9 (emphasis added) ("To ensure that departing load does not pay for above-market costs of utility *procurement commitments* after the load departs, the Commission approved the vintage methodology for DA departing load to ensure the proper matching of departing load with the utility procurement process.").

86 *See, e.g.,* D.08-09-012 at 66 ("We will also adopt SCE's related proposal that 'the time a commitment is made' is when the IOU executes a contract….").

87 D.05-01-031 at 39.

88 In D.05-01-031, the Commission was examining cost responsibility under Standard Offer Contracts.

buydown, or renegotiation'" would affect customer cost responsibility, whereas "Commission ordered" extensions would not affect customer cost responsibility.[89] As described below, PG&E clearly "renegotiated" the four contracts at issue. As such, customer cost responsibility (i.e., "vintaging") must be reexamined.

The Commission recently reiterated this point in a similar context involving "renewed" contracts, reaffirming its expectation that modified contracts should be treated differently for cost responsibility purposes. In Resolution E-5095, "vintaging" of contracts was examined and a clear distinction was made with respect to "renewed" contracts. A respondent to a Southern California Edison Company ("SCE") advice letter raised a concern about a renewed contract and sought clarification that "extended, renewed or amended contracts will not retain the original contracts' respective vintage, but rather will have a vintage associated with the new effective date for the contract."[90] In response, the Commission stated its expectation that SCE should treat renewed contracts consistent with statements made by SCE, namely, that renewed contracts would be placed in a later vintage comporting with the new commitment date, instead of an earlier vintage associated with the original execution date.[91]

Second, the Commission should apply a legal test of "materiality" to determine when a contract modification must result in the re-assignment of a contract to a new vintage year. In Resolution E-4841, the Commission was asked to address whether amendments to power purchase agreements between PG&E and solar project developers related to Ivanpah Unit #1 and Ivanpah Unit #3 should result in a re-assignment of the vintage year of those contracts.[92] The amendments to those PG&E contracts pertained to two subjects, 1) adding a limit on the total

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[89] *See* D.05-01-031 at 39.
[90] Resolution E-5095 at 9.
[91] *See id.* at 10 (referencing SCE's Reply, dated May 14, 2020, at 4).
[92] *See* Resolution E-4841 at 9-10.

deliveries for which PG&E was required to pay the full contract price and 2) providing PG&E with curtailment rights and the solar company with the opportunity to pay damages to cure certain failures.[93] After a review of the contracts and the amended terms, the Commission concluded that the amendments to the Ivanpah solar contracts did not affect material contract terms, such as price.[94] The Commission therefore did not examine whether re-vintaging of the contracts was appropriate.[95]

Resolution E-4841 reflects a reasoned basis for determining when contracts must be re-vintaged and when they need not be, namely, a materiality test.[96] The logical conclusion of the test applied in Resolution E-4841 is that a contract must be re-vintaged when new commitments have been made to material contract terms.[97]

In 2019, PG&E had the opportunity to renegotiate the contracts for the RE Gaskell West 3, 4, and 5 facilities, as well as to renegotiate its agreement for the Java Solar resources for the second time in two years.[98] PG&E acknowledges that it renegotiated these four PCIA-eligible contracts in 2019 as follows:[99]

Project Name	Log Number	Vintage
RE Gaskell West 3	33R419	2017
RE Gaskell West 4	33R420	2017
RE Gaskell West 5	33R421	2017
Java Solar	33R393	2016

93 *Id.* at 5.
94 *See id.* at 10.
95 *See id.*
96 *See id.*
97 *See id.*
98 *See* Resolution E-5027 at 9-10 (November 7, 2019); Resolution E-5049 at 2 (January 21, 2020) (approving second set of amendments to Java Solar Contract, following amendments in 2017 approved in Resolution E-4890 (December 14, 2017)).
99 Exh. JCCAs-1 at 57:22-23 (citing PGE-1, Chapter 9, Table 9-9, Lines 19-21 and 26; PG&E Data Response to Joint CCAs DR 003, Q047 and CONF DR 009, Q001).

As part of its negotiations in 2019 to amend the contracts in order to extend the commercial operation date, PG&E successfully achieved price reductions or a "buydown"[100] of approximately 10% for each contract, among other modifications to the four contracts.[101] PG&E further acknowledges that although it renegotiated and modified these contracts in 2019, it did not assign any of the contracts to a new vintage year.[102] Consequently, the contracts are still listed as part of the 2016 and 2017 PCIA vintages.[103]

All four of the contracts that the Joint CCAs highlight in the chart above were materially modified during the compliance period and therefore should be reassigned to the 2019 vintage. As noted, PG&E successfully achieved price reductions or a buydown of approximately 10% for each these contracts, among other amendments.[104] Under the reasoning set forth in Resolution E-4841, amendments to price terms such as these constitute material changes.[105] Consistent with that reasoning, basic doctrines of contract law also dictate that price is a material contract term.[106] Indeed, under contract law, if there is no meeting of the minds as to the price term in a contract, then there is no valid agreement.[107] Moreover, a 10% price difference is sufficiently substantial to be considered a material price difference.[108]

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[100] *See* note 28, *supra* (citing D.05-01-031 at 39).

[101] Exh. JCCAs-1 at Attachment 2, PG&E Data Response to Joint CCAs CONF DR 009, Q001. *See also* Resolution E-5027 at 9-10; Resolution E-5049 at 2 (January 21, 2020).

[102] Exh. JCCAs-1. at 58:7-8.

[103] *Id.* at 58:3-4, 8-9.

[104] *See id.* at 58:1-2 and Attachment 2, PG&E Data Response to Joint CCAs CONF DR 009, Q001.

[105] *See* Resolution E-4841 at 9-10.

[106] *Donovan v. Rrl Corp.*, 26 Cal. 4th 261, 282 (2001) (in establishing a material mistake regarding a basic assumption of the contract, counterparty can show a failure of the meeting of the minds as to price).

[107] *See id.*

[108] *Cf. Elsinore Union Elementary School Dist. v. Kastorff*, 54 Cal. 2d 380, 389 (1960) (7% price difference "plainly material"); *Lemoge Electric v. County of San Mateo*, 46 Cal. 2d 659, 661-62 (1956) (6% price difference material).

Under the test applied in Resolution E-4841, the amendment of price terms in these contracts is therefore material.[109] Moreover, consistent with principles articulated by the Commission in D.05-01-031, D.08-09-012 and Resolution E-5095, new commitments were made when these contracts were renegotiated and amended – new commitments that implicate customer cost responsibility. Therefore, PG&E's new commitments should trigger a re-vintaging of all four contracts that were renegotiated.

To be clear, when the Commission directs PG&E to re-vintage these contracts, PG&E will continue to recover the costs of the contracts from both bundled and unbundled customers. However, PG&E will recover the costs incurred under these contracts from customers who departed in 2019 and after, rather than customers who departed prior to the renegotiated contracts.[110]

There were no costs recorded under these agreements while they were the subject of renegotiation in 2019,[111] so no revisions to the recorded PABA amounts in 2019 are required. However, once the resources are completed and begin operation, PG&E will record the costs under these renegotiated agreements in the PABA under the 2016 and 2017 vintages,[112] unless the contracts are re-assigned to the 2019 vintage. While it may also be appropriate for the Commission to require these contracts be re-vintaged as part of a future ERRA forecast or compliance proceeding, *i.e.*, once costs regarding the contracts are or will be recorded, the Joint CCAs contend this ERRA Compliance proceeding is the right proceeding in which to address re-vintaging since the contracts were amended in the 2019 record year, and since PG&E lists the contracts as 2016 and 2017 vintage contracts in its 2019 ledger.

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109 *See* Resolution E-4841 at 9-10.
110 *See* Exh. JCCAs-1 at 58:15-18.
111 *Id.* at 58:15 and Attachment 2, PG&E Data Response to Joint CCAs CONF DR 009, Q001.
112 *Id.* at 58:15-17.

B. ERRA Compliance Proceedings are the Appropriate Venue to Review Whether the Tens of Contracts PG&E's Modifies Each Year Are Correctly Vintaged.

The ERRA compliance proceeding is the ideal forum for the Commission to re-assign contract vintages as necessary. PG&E amends tens of contracts each year, and amended 30 different procurement contracts in 2019 alone.[113] Addressing re-vintaging here, rather than in individual contract-related advice letters submittals, ensures the full Commission resolves contract re-vintaging issues that pertain to the fairness of cost recovery and that may give rise to contentious disputes and raise legal and policy questions.[114] Concurrently, it resolves the administrative inefficiency that may result from the full Commission having to address re-vintaging on a large number of material modifications within a given year, *i.e.*, where parties might be filing protests and responses solely to address re-vintaging rather than the reasonableness of the underlying contractual terms.

All parties affected by PCIA-related financial impacts including vintaging have full and fair notice and opportunity to participate in ERRA compliance proceedings. In contrast, Advice letter dockets are not procedurally amenable to resolving fact-based questions that rely on confidential information. There is no formal discovery process available in an advice letter process, and there frequently is no underlying docket for which a market participant like a CCA would have already signed a non-disclosure agreement ("NDA"). Attempting to analyze an advice letter, retain a reviewing representative, have that representative obtain and sign the appropriate NDA to gain access to the confidential terms, analyze those terms, propound

113 Exh. PG&E-1 at Table 9-9.

114 *See* A.01-05-032 *et al.*, *Order Modifying Resolution M-4801 and Denying Rehearing of the Decision as Modified*, p. 6 (February 27, 2002) ("D.02-02-049") (final policy decisions to be made by the Commission); General Order 96-B at Section 7.6 (only "ministerial" matters may be delegated to Industry Division).

discovery or request other factual information, obtain expedited replies on that discovery (assuming the utility is willing and able to respond to such a request), and draft a protest on substantive vintaging issues in the 20-day process provided for under General Order 96-B is extremely difficult. It is much more administratively efficient to resolve re-vintaging issues in an ERRA compliance docket where all of the relevant facts concerning multiple contracts, amendments, and vintaging issues are compiled by the utility into a single document, the IOU's direct testimony.[115]

The existing scope of this proceeding also aligns well with addressing re-vintaging here. This is the forum where the Commission not only ensures costs are recorded to the right vintages during the record year, but it is also the forum where the Commission reviews the IOU's portfolio optimization practices under Standard of Conduct 4.[116] Addressing the impacts on vintaging of portfolio optimization, concurrent with considering optimization itself, makes administrative sense and allows the Commission to consider the impacts of optimization in a holistic manner.

V. CONCLUSION

For the foregoing reasons, the Joint CCAs respectfully request the Commission:

- Reject PG&E's request to reverse its $92.9 million adjustment and order the utility to adjust the PABA by $2.4 million, plus interest, to reflect the actual $95.3 million value of retained RPS;
- Order PG&E to re-vintage the four renegotiated PPAs as 2019-vintage contracts; and
- Provide any other relief the Commission deems just and reasonable.

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115 *See* Exh. PGE-1.

116 Amended Scoping Ruling at 2.

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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 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 20-07-002 (Filed July 1, 2020)

OPENING BRIEF OF THE JOINT COMMUNITY CHOICE AGGREGATORS

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October 30, 2020

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OPENING BRIEF OF THE JOINT COMMUNITY CHOICE AGGREGATORS

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), and the schedule set forth in Commissioner Guzman Aceves's September 10, 2020 Scoping Ruling ("Scoping Ruling"),[1] Central Coast Community Energy, CleanPowerSF,[2] East Bay Community Energy ("EBCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Pioneer Community Energy Authority, San José Clean Energy ("SJCE"), Silicon Valley Clean Energy Authority ("SVCE"), Sonoma Clean Power, and Valley Clean Energy Alliance (collectively "the Joint CCAs" or "JCCAs") hereby submit this Opening Brief in opposition to the *Application of Pacific Gas and Electric Company ("PG&E") for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account ("ERRA") and Generation Non-*

[1] A.20-07-002, *Assigned Commissioner's Scoping Memo and Ruling*, pp. 4-5 (September 10, 2020) ("Scoping Ruling").

[2] CleanPowerSF is the CCA for the City and County of San Francisco ("San Francisco") operated by the San Francisco Public Utilities Commission; San Francisco is a party to this proceeding.

Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation ("Application").

I. INTRODUCTION AND SUMMARY

PG&E's Application will unreasonably increase the Power Charge Indifference Adjustment ("PCIA") for all customers, including the Joint CCAs' customers, via a requested revenue requirement of $2,802.6 million,[3] resulting in a requested *single-year* PCIA rate increase of between 16% and 21% for vintages 2009 through 2018.[4] The increase is unreasonable and unlawful, and the Commission should not grant the PCIA-related relief PG&E requests in the Application without modification. PG&E has also not correctly calculated the Resource Adequacy ("RA") component of its Green Tariff Shared Renewables ("GTSR") and Enhanced Community Renewables ("ECR") rates, and it has inappropriately excluded pending budgets for CCAs' disadvantaged communities ("DAC") green tariff and ECR programs from the overall 2021 budget proposal for those programs.

In total, the utility has not met its burden of proof on the following issues in Commissioner Guzman Aceves' September 10, 2020 Scoping Ruling:[5]

Issue a. Whether PG&E's requested 2021 ERRA forecast revenue requirement, ongoing Competition Transmission Charge (CTC), Power Charge Indifference Amount (PCIA), Cost Allocation Mechanism (CAM), and Tree Mortality Non-Bypassable Charge are reasonable and should be adopted;

Issue c. Whether the Commission should adopt PG&E's Greenhouse Gas (GHG) related forecast for 2021 of GHG allowance revenues and returns, including

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3 Exh. JCCAs-1 at 5:4-5.

4 *Id*. at 3:9-11 and p. 3, Table 1. The 2019 and 2020 vintage rates decrease due to crediting the PABA for the respective share of PG&E's ERRA overcollection balance. Exh. JCCAs-1 at 3:11-13.

5 Scoping Ruling at 2-3. Scoping item b) Whether the Commission should adopt PG&E's 2021 electric sales forecast relates to information and updates provided by PG&E on October 26, 2020. PG&E filed supplemental testimony concerning the 2021 load forecast on that date, leaving insufficient time for the Joint CCAs to address this issue in testimony or in this brief. The Joint CCAs will address that issue, as necessary, in our response to the November Update.

Administrative and Outreach Expenses, GHG administrative and outreach set-aside true-up, Customer Generation Program Expenses, Net GHG revenue return, and per household Semi-Annual Residential California Climate Credit;

Issue d. Whether all calculations and entries, including but not limited to ERRA, Ongoing CTC, PCIA, CAM, procurement costs, and GHG related items, including the funding of GHG clean energy programs such as the Solar on Multifamily Affordable Housing program, are in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes;

Issue e. Whether PG&E's or any other party's rate proposals associated with PG&E's proposed total electric procurement revenue requirements for 2021 should be approved;

Issue f. Whether the Commission should approve PG&E's proposal to credit the 2019 ERRA overcollection to vintage 2019 and vintage 2020 customers; and

Issue g. Whether the Commission should approve PG&E's proposal to transfer certain year-end ERRA balances, excluding deferred revenue resulting from capped vintage PCIA rates, through a balancing account transfer to the latest vintage in Portfolio Allocation Balancing Account in the current proceeding and on a going-forward basis.

Parts of PG&E's request are either not in compliance with prior Commission rules, regulations, resolutions and decisions, or are unsupported by substantial and verifiable evidence. PG&E's Application and testimony also include costs, refunds, and cost reductions that have not been authorized by the Commission. As a result, PG&E's rate proposals are unjust and unreasonable and should not be adopted as proposed. Instead, the Commission should:

- Refund the balance owed to recently departed bundled customers from the PCIA Undercollection Balance Account ("PUBA") Financing Subaccount via PCIA rates rather than ERRA rates;

- Reject PG&E's proposed GTSR and ECR rates, revising the RA charge within the rates to be $0.01312/kWh.

- Include funding for CCA DAC-green tariff and ECR programs in the overall 2021 budget proposal for those programs; and

- Order PG&E to provide monthly, aggregated volumetric data as part of its workpapers in future ERRA forecast proceedings because PG&E's current showing fails to meet the burden of proof.

In addition, PG&E largely has agreed to make over $250 million adjustments to its requested revenue requirement related to (1) using only General Rate Case ("GRC") revenue requirements that have been approved to date, (2) excluding unapproved Wildfire Expense Memorandum Account ("WEMA") costs, (3) making an adjustment to forecasted Retained RA capacity from six different contracts to purchase Local RA capacity, and (4) making an adjustment to the PABA related to *2019* Retained Renewable Portfolio Standard ("RPS") energy that was ordered eight months ago in D.20-02-047 (an issue PG&E has tried to litigate for the *fourth time* in this proceeding). These issues, and acknowledgement that PG&E has addressed the Joint CCAs' concerns regarding incremental Central Procurement Entity ("CPE") costs, are discussed in more detail as Uncontested Issues in Section VI below.

Adopting the Joint CCAs' recommendations results in a PCIA revenue requirement of $2,537.6 million compared to PG&E's proposal of $2,802.6 million, a 9.5% reduction that benefits both bundled and unbundled customers.[6] For unbundled customers the PCIA revenue requirement would be $1,713.5 million rather than the $1,864.3 million proposed in PG&E's testimony, an 8.1% reduction.[7] For bundled customers the PCIA revenue requirement would be $824.1 million rather than the $938.2 million proposed in PG&E's Supplemental Testimony, a 12.2% reduction.[8] Based on the current record, these modifications result in the rates below from Table 3 in the Joint CCAs' Opening Testimony:[9]

6 Exh. JCCAs-1 at 5:4-5.

7 *Id*. at 5:6-7 (citing to Exh. PG&E-3 at Table 19-6).

8 *Id*. at 5:7-9 (citing to Exh. PG&E-3 at Table 19-6).

9 *Id*. at p. 6, Table 3.

Table 3: Joint CCAs Adjusted PCIA Rates

Vintage	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2020 Capped	$0.0243	$0.0273	$0.0297	$0.0296	$0.0316	$0.0321	$0.0319	$0.0318	$0.0317	$0.0317	$0.0338	$0.0406	
2020 Uncapped	$0.0326	$0.0394	$0.0414	$0.0431	$0.0437	$0.0438	$0.0439	$0.0434	$0.0427	$0.0420	$0.0406	$0.0406	
2021 Capped	$0.0293	$0.0323	$0.0347	$0.0346	$0.0366	$0.0371	$0.0369	$0.0368	$0.0367	$0.0367	$0.0388	$0.0456	
2021 Uncapped	$0.0321	$0.0383	$0.0400	$0.0417	$0.0421	$0.0423	$0.0425	$0.0424	$0.0433	$0.0436	$0.0434	$0.0270	$0.0270
2019 ERRA Refund											-$0.0082		
Proposed Rates	$0.0293	$0.0323	$0.0347	$0.0346	$0.0366	$0.0371	$0.0369	$0.0368	$0.0367	$0.0367	$0.0306	$0.0270	$0.0270
Capped?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	
Proposed % Rate Change	21%	18%	17%	17%	16%	16%	16%	16%	16%	16%	-9%	-34%	

The rates in Table 3 are preliminary and remain subject to change as the PCIA revenue requirement is updated in PG&E's updated November testimony ("November Update").[10] In fact, the final increase to the PCIA revenue requirement and resulting uncapped PCIA rates are likely to be substantially greater than the proposal in the Application given the current status of the Portfolio Allocation Balancing Account ("PABA") year-end balance.[11] In PG&E's August 2020 ERRA Monthly Activity Report, the year-to-date PABA under-collection had reached a staggering $1,167.4 million by the end of July.[12] Removing the balance in the PCIA Subaccount, which is not included in determining 2021 PCIA revenue requirement, results in a July 2020 balance of $948.3 million, over 75% higher than the $537.8 million projected as the year-end PABA balance in the Application (prior to the application of an ERRA-related credit).[13] Given these increases, it is important that the November Update accounts for the Joint CCAs' recommended adjustments.

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10 *Id*. at 6:5-6.

11 *Id*. at 6:6-9.

12 *Id*. at 6:9-10.

13 *Id*. at 6:10-14 and Attachment B, PG&E's response to Joint CCA DR 4.01, Confidential Attachment 1. Total balance not marked as confidential. It is possible the billion-dollar actual balance will be reduced over the rest of 2020, but the difference is enormous, especially given the fact that PG&E's forecast for the remainder of 2020 assumes no load reduction from COVID-19.

Other critical issues that should be addressed in the November Update are discussed in Section V below, including the potential impact of PG&E's PUBA Trigger Application, A.20-09-014, PG&E's forecast for Unsold RA in 2021, which is currently zero MW,[14] PG&E's October 26, 2020 updated load forecast related to the on-going pandemic,[15] as well as ensuring PG&E has correctly implemented Energy Division's updated market price benchmarks and the numerous other components of its PCIA revenue requirement that still remain unresolved for 2021.

II. LEGAL STANDARD

The magnitude of the impact of PG&E's application on both departed and bundled customers requires cautious and careful consideration under the applicable standards of proof. PG&E, as the applicant, has the burden to affirmatively establish the reasonableness of all aspects of its application,[16] and that burden of proof generally is measured based upon a preponderance of the evidence.[17]

The Commission cannot grant the relief requested in PG&E's Application without substantial evidence to support the rates requested therein.[18] California courts will overturn

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14 Exh. JCCAs-1 at 10-12 (citing to Exh. PG&E-1 at 9-4:7 and n.13); Exh. PG&E-4 at 10:17 to 11:22.

15 *See* Exh. PG&E-5.

16 R.11-02-019, *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering,* p. 42 (December 28, 2012) ("D.12-12-030").

17 *See, e.g.,* A.17-06-005, *Decision Adopting Pacific Gas and Electric Company's 2018 Energy Resource Recovery Account Forecast and Generation Non-Bypassable Charges and Greenhouse Gas Forecast Revenue and Reconciliation*, pp. 9-10 (January 16, 2018) ("D.18-01-009"); R.11-02-019, *Order Modifying Decision (D.) 12-12-030 and Denying Rehearing, as Modified,* p. 29 (July 27, 2015) ("D.15-07-044") (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.").

18 Cal. Pub. Util. Code § 1757(a)(4). *See, e.g., The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (February 5, 2014).

Commission decisions that lack substantial evidence.[19] Mere rubber-stamping of uncorroborated, disputed evidence does not meet this standard.[20] The Commission, therefore, must require PG&E to support its assertions with sufficient evidence or reject the components of PG&E's Application unsupported by substantial evidence.

Further, PG&E's forecast must be in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes that exist at the time of the forecast.[21] Decision 18-01-009 expressly found that policy issues and other industry-wide practices such as changes to the PCIA methodology are properly addressed in rulemaking dockets, such as R.17-06-026.[22]

III. THE COSTS OF PG&E'S PORTFOLIO CONTINUE TO RISE WHILE ITS VALUE CONTINUES TO DECLINE.

A. How PCIA Rates are Calculated.

The Joint CCAs' Direct Testimony includes a detailed discussion of how the PCIA is calculated each year.[23] In summary, PG&E's PCIA rates for 2021 will be set in this proceeding based on two key components: (1) the forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of PG&E's generation portfolio in 2021 and the forecasted market value of PG&E's generation portfolio in 2021; and (2) the 2020 year-end balance in the PABA.[24] Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact true-up

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19 Cal. Pub. Util. Code § 1757(a)(4). *See, e.g., The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 958-9 (February 5, 2014).

20 *See id*.

21 *See, e.g.*, Scoping Ruling at 2-3; A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner*, p. 4 (September 12, 2013).

22 D.18-01-009 at 10.

23 Exh. JCCAs-1 at 7:13 to 12:2.

24 *Id*. at 10:15-18.

for unbundled customers.[25] That decision approved a true-up for the PCIA using actual recorded net costs for PCIA-eligible resources and billed revenues from both bundled and departing load customers.[26] This true-up now occurs via the PABA, a rolling true-up between the forecasted costs and revenues used to determine the Indifference Amount and the actual costs and revenues PG&E realizes during the year related to its PCIA eligible resource portfolio (*i.e.*, in this case, 2020).[27]

The Indifference Amount and the year-end PABA balance are added together to form the revenue requirement underlying PCIA rates.[28] The PCIA revenue requirement is allocated among both bundled and unbundled customers based on their vintage, *i.e.*, the year unbundled customers left PG&E's service,[29] and their rate class using the allocation factors from PG&E's most recently approved GRC.[30] Bundled customers form the current year's vintage.

Decision 18-10-019 limited "the change of the PCIA from one year to the next. Starting with forecast year 2020, the cap level of the PCIA rate should be set at $0.005/kWh more than the prior year's PCIA, differentiated by vintage."[31] If departing load rates would exceed the rate cap in a given year, bundled customers rates are increased instead to 'finance' the amount above the cap.[32] A separate balancing account, the PUBA, was also established to record the shortfall in revenue charged to departing load customers due to PCIA rates being limited by the

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25 *Id*. at 10:8-9.

26 *Id*. at 10:9-11.

27 *Id*. at 10:11-14.

28 *Id*. at 11:1-2.

29 D.11-12-018, p. 9 (December 1, 2011); Exh. JCCAs-1 at 11:8-10.

30 D.18-10-019, p. 122 and Ordering Paragraph 4 (October 11, 2018); Exh. JCCAs-1 at 11:8-10.

31 D.18-10-019 at Conclusions of Law 19-20, Ordering Paragraph 9(a)-(c) (October 11, 2018).

32 Exh. JCCAs-1 at 11:13-15.

$0.005/kWh cap in annual rate changes.[33] Unbundled customers are responsible to pay for the shortfall recorded to PUBA, plus interest, to compensate bundled customers for having paid for the amount in excess of the cap.[34]

B. Status of the PCIA and PABA

PG&E's 2021 ERRA Forecast application continues the trend of significant annual increases to the PCIA.[35] The proposed 2021 Indifference Amount is more than 6 times larger than in 2013 – an annual growth rate of 26%.[36] The advent of the PABA in D.18-10-019 tacked on an additional $621 million to the PCIA revenue requirement in 2019, a 25% increase in a single step.[37] Even with the PCIA rate cap, PCIA rates for most departing load customers will increase at least 16% in 2021.[38]

Figure 1 from the Joint CCAs' direct testimony below illustrates the rapid increase in the PCIA revenue requirement since 2013.[39] It also demonstrates the step change occurring with the introduction of the PABA, and the potential impact of shifting the timing of cost recovery from departed load customers through the PUBA.[40]

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33 *Id*. at 11:15-19.

34 *Id*. at 11:18 to 12:2.

35 *Id*. at 12:7-8.

36 *Id*. at 12:8-9.

37 *Id*. at 12:9-11.

38 *Id*. at 12:11-12.

39 *Id*. at 12:16-17.

40 *Id*. at 12:17-19.

Figure 1: PCIA Revenue Requirement 2013 - 2021

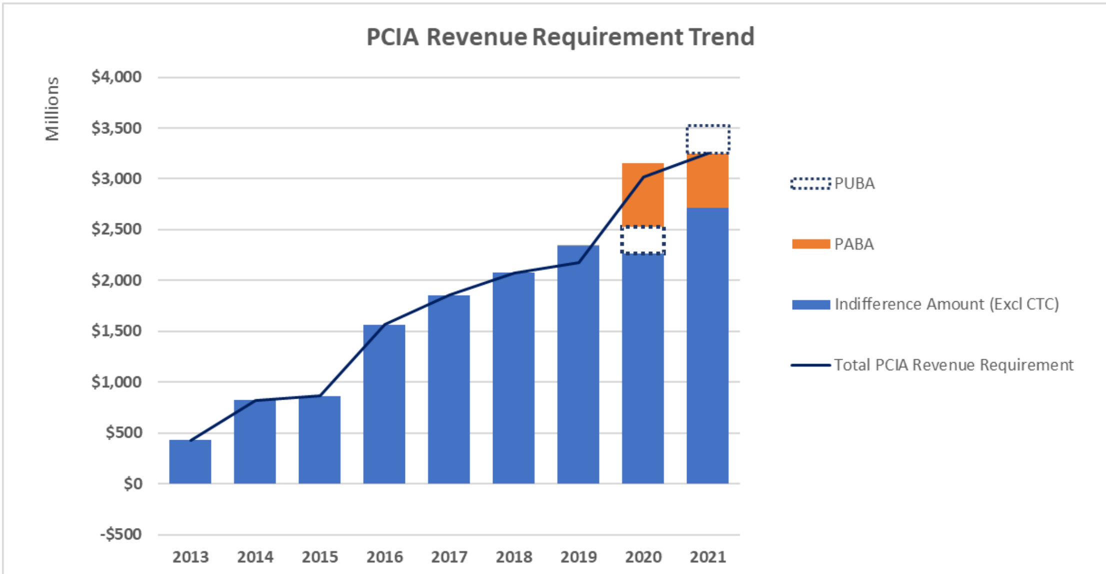
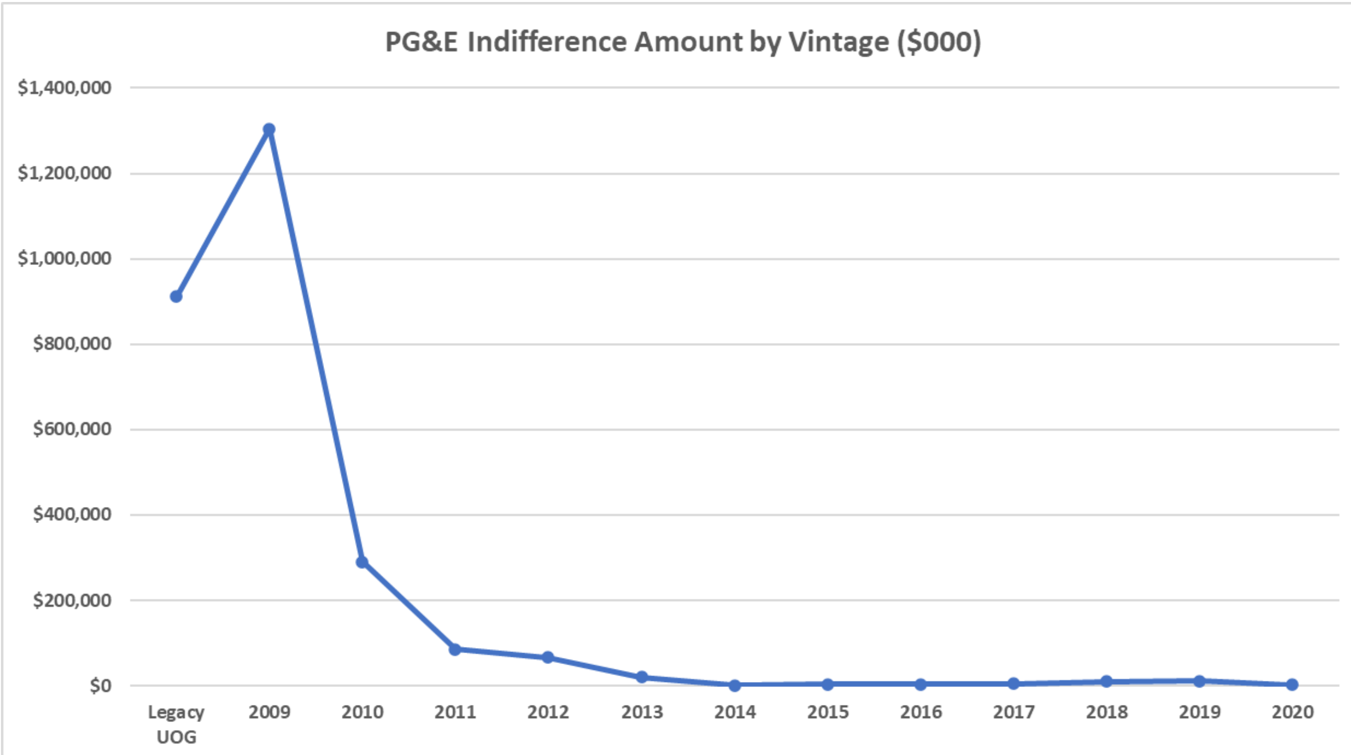


Figure 2 from the JCCAs' testimony reveals that 98% of the above market costs projected in 2021 are attributed to PG&E's Legacy UOG and resource vintages prior to 2013.[41]

41 *Id*. at 13:3-7 and p. 14, Figure 2.

Figure 2: Indifference Amount by Vintage

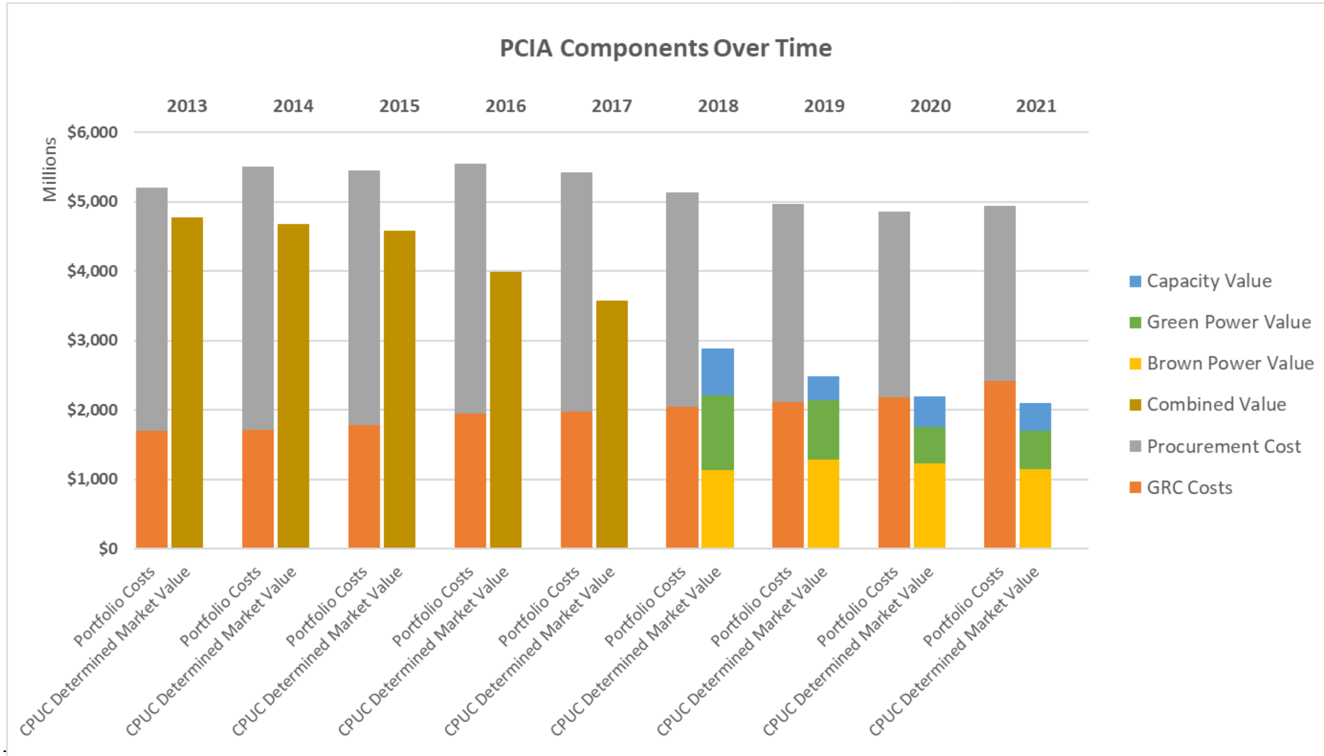


The growth in the Indifference Amount since 2013 can be attributed to a sharp reduction in the Commission's administratively determined market value of PG&E's resource portfolio and a steady increase in GRC-related costs of the UOG resources.[42] Figure 3 compares the change in major PCIA components—including GRC and procurement costs, offset by portfolio market value—between 2013 and 2021.[43]

42 *Id*. at 14:3-5.

43 *Id*. at 14:6-7 and p. 15, Figure 3.

Figure 3: PCIA Components Over Time



Since 2013 total portfolio costs have remained relatively flat, but the stability in total costs masks the offsetting changes in fixed GRC costs versus variable production costs.[44] As shown in Figure 3, GRC costs have grown 5% annually since 2013 while variable production costs have fallen at an annual rate of 4%.[45] Over that same period, the CPUC's changing administrative measure of short-term market value has fallen at a rate of 9% per year and is less than half the dollar value than it was in 2013.[46] Notably, for the first time in the 2021 forecast, total portfolio market value is less than the GRC-related fixed costs of PG&E's portfolio.[47]

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44 *Id*. at 15:3-5.

45 *Id*. at 15:5-6.

46 *Id*. at 15:6-8.

47 *Id*. at 15:8-10.

IV. CONTESTED ISSUES

A. Issues Related to PG&E's Ratemaking Proposals.

1. PG&E's Proposal to Transfer Year-End ERRA Balances Does Not Meet the Standard Set Forth in D.20-02-047 and Should Not Set Precedent for Future ERRA Forecast Cases.

PG&E's proposal to transfer year-end ERRA balances to PABA does not comply with the Commission's directive in D.20-02-047. In D.20-02-047, the Commission "agree[d] with the Joint CCAs that the net ERRA overcollection must be reflected in the PCIA rate," and that the "overcollection credit should benefit all customers who paid into the overcollection."[48] The Commission ordered PG&E to "include in its Energy Resource Recovery Account Forecast application for 2021 a method to properly credit vintage 2019 and 2020 departed load customers that does not have adverse effects on PCIA vintage subaccounts."[49]

In its Prepared Testimony, PG&E proposes to credit a proportional share of the 2019 ERRA end-of-year balance to 2019 vintage departing load customers through a one-time PCIA rate adjustment for that vintage.[50] PG&E also proposes that the end-of-year ERRA balance going forward, "less the deferred revenue financed by bundled customers due to capped PCIA rate," be returned to the 2020 vintage and that this approach be standardized for future years.[51] PG&E explained the purpose of the transfer is to "ensure that the 2020 overcollected ERRA is returned to the Vintage 2020 non-exempt departing load customer and remaining bundled customers."[52] Because customer vintages are determined on a July to June schedule, PG&E's proposal to

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48 D.20-02-047 at 11.

49 D.20-02-047 at Ordering Paragraph 4.

50 Application at 5, 12-13, 18, 21; Exh. PG&E-1 at 19-4:22-25.

51 Exh. PG&E-1 at 19-7:6-15.

52 *Id*. at 14-14:2-4.

transfer year-end ERRA balances to the most recent vintage on a going-forward basis would ensure customers departing "on or after July 1" are credited (or charged) for the ERRA balance accruing during the year of their departure.[53]

However, the proposal does not include a similar credit (or debit) for customers that would depart PG&E's bundled service between January and June in future years.[54] In response to discovery and in rebuttal testimony, PG&E confirmed that customers departing between January and June 2020 would not be included in a credit or refund for the 2020 year-end ERRA balance.[55] As a result, PG&E's proposal does not ensure that the overcollection credit will benefit all customers who paid into the overcollection, as D.20-02-047 requires.[56]

In acknowledging that its proposal does not meet the Commission's standard, PG&E offers two explanations. First, PG&E explains approximately half of the vintage of affected customers will be made whole. Those customers receiving a share of the balance are those who departed on or after July 1, 2020 (or remain bundled PG&E customers) and paid into ERRA for at least the first half of 2020.[57]

The second is due to the mid-year customer vintage convention. If the ERRA balance is transferred to the 2019 vintage rather than the 2020 vintage, customers that depart between July 1, 2019 and December 31, 2019 would benefit from the transfer of the 2020 ERRA balance despite not having paid into ERRA during 2020.[58] Stated another way, PG&E's proposal would result in

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53 Exh. JCCAs-1 at 37:20 to 38:3.

54 *Id*. at 38:4-5.

55 *Id*. at Attachment B, PG&E's response to Joint CCA DR 3.34; Exh. PG&E-4 at 19:28 to 20:1.

56 D.20-02-047 at 11.

57 Exh. JCCAs-1, Attachment B, PG&E's response to Joint CCA DR 3.34.

58 *Id*.; Exh. PG&E-4 at 20:1-15.

one group of customers not being made whole because doing so might unjustly benefit another group of customers.[59]

The JCCAs do not oppose this unjust result for purposes of this proceeding only. Confidential Table 8 in the JCCAs Direct Testimony shows that the share of the 2020 ERRA balance attributed to customers departing between January and May 2020 is *de minimis* and would not impact departed customers' rates.[60] Given this small impact, PG&E's proposal, while unjust, is not unreasonable given the current framework for establishing and tracking PCIA and ERRA rates and the Commission's directive in D.20-02-047 to devise a solution with no "adverse effects on PCIA vintage subaccounts." The current PCIA framework creates a quandary in that the different timelines used to set PCIA rates and to determine a customer's vintage mean some customers that overpaid their ERRA obligations cannot be made whole without benefitting other customers that did not pay the ERRA during the timeframe at issue.[61]

While the impact this year is minimal, it is not clear the same will be always be true going forward.[62] If the impact in future years becomes material, more nuanced solutions will be required.[63] For this reason, PG&E's approach in this case should not be the approach used in future years in all circumstances.[64]

In addition, the Commission should consider changes to the PCIA framework overall to address this issue. PG&E states in rebuttal that "if the PCIA framework is modified to

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59 Exh. JCCAs-1 at 16-17.

60 *Id*. at 38:18 to 39:15.

61 *Id*. at 39:18 to 40:4.

62 *Id*. at 39:18 to 40:5-6.

63 *Id*. at 39:18 to 40:6-7.

64 *Id*. at 39:18 to 40:7-8.

accommodate a return to customers that depart in the first half of the year, PG&E will propose revisions to this mechanism."[65] One such potential change would be to align the time periods for determining a customer vintage and the period for setting PCIA and ERRA rates.[66]

2. If Not Resolved by the PUBA Trigger Application, the Balance Owed to Bundled Customers for PUBA Financing Should be Treated the Same as the ERRA Balance.

PG&E's proposal to return the PCIA Financing Subaccount to bundled customers via the ERRA rather than the PABA is unjust and unreasonable, depriving recently departed customers of funds owed to them under the Commission's PUBA framework. PG&E has not identified any compelling reason in this proceeding why it should not follow the same approach it has proposed for ERRA overcollections, discussed in the previous section.

The PCIA Financing Subaccount of PG&E's ERRA is used to track the amount financed by bundled customers related to the PUBA, that is, the revenue shortfall associated with capped PCIA rates for departing load customers.[67] In its Prepared Testimony PG&E refers to the PCIA Financing Subaccount as a "revenue deferral"[68] and projects the balance will reach $286 million by the end of 2020.[69] PG&E proposed to carve out "the deferred revenue financed by bundled customers due to capped PCIA rate"[70] from the ERRA balance and exclude it from the amount that is proposed to be transferred to the PABA.

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65 Exh. PG&E-4 at 20:13-15.

66 Exh. JCCAs-1 at 39:18 to 40:9-11.

67 *Id*. at 40:15-17.

68 Exh. PG&E-1 at 1-12:19-22.

69 Exh. JCCAs-1 at 40:18-19 (citing to PG&E workpapers 14.ERRA 2021-Forecast_WP_PGE_202007001_Ch14_PUBLIC, tab 'One Time Adjustments.').

70 *See* Exh. PG&E-1 at 19-7:6-15.

PG&E's suggested approach is unfair. The revenue deferral is functionally equivalent to an ERRA overcollection in that both represent a credit owed to bundled customers that should be paid to those customers even if they depart.[71] Returning an ERRA overcollection to bundled customers has the same effect as reimbursing bundled customers for having financed the PUBA – a reduction to future generation rates paid by bundled customers.[72] As such, it should be paid back in the same manner prescribed by D.20-02-047 for an ERRA overcollection, *i.e.*, "reflected in the PCIA rate" to ensure any overcollection credit benefits "all customers who paid into the overcollection."[73]

If the revenue deferral is effectuated only as a reduction to bundled rates, a customer who contributed to the revenue deferral prior to the PUBA Trigger Application but then leaves bundled service, would no longer receive a credit or refund related to the revenue deferral.[74] PG&E all but concedes this unfair treatment would occur, stating in Rebuttal Testimony that it agrees that "customers that depart bundled service in a given year when PCIA rates are capped may have contributed to financing the PCIA cap at some point during the year;"[75] although it leaves unstated the fact that departed customers do not pay ERRA rates. As such, they would not receive a refund in the form of a reduction to ERRA rates. Under the JCCAs' proposal, similar to the ERRA refund treatment discussed in the previous section, if the revenue deferral is transferred

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71 Exh. JCCAs-1 at 41:8-11.

72 *Id*. at 41:11-13.

73 D.20-02-047, p. 11.

74 Exh. JCCAs-1 at 41:17-20.

75 Exh. PG&E-4 at 22:16-18.

to the latest PABA vintage, customers would receive credit whether they remain bundled customers or choose to take unbundled service.[76]

PG&E's rebuttal testimony appears to suggest that an arbitrary designation of these funds as "revenue deferral," discussion of the funds having "separate properties," concerns about "complexity," and the chance for "unintended consequences" somehow justifies the unfair results from its proposal.[77] However, the JCCAs' proposal allows for the concurrent repayment of the PCIA revenue shortfall financing with PUBA repayment and allows for only a specified portion to be refunded if the entire balance is not amortized. The accumulation of the two balancing accounts is independent and based on the usage of the different customer groups.[78] It is not necessary or required to match the return of the deferred revenue with the recovery of the PUBA balance from departed load customers,[79] although in circumstances different than those presented here, it may make sense to do so.

Further, PG&E raised similar concerns about complexity and skewing the rate cap with regard to refunding ERRA overcollections, and the Commission determined in D.20-02-047 that such concerns do not outweigh considerations of fairness, concluding the "overcollection credit should benefit all customers who paid into the overcollection."[80] Similarly here, credits from the PCIA Financing Subaccount should benefit all customers who provided such financing.

That is the approach followed by SCE. When SCE created its version of the PCIA Financing Subaccount, it set up the Bundled Service Financing subaccount of the PUBA (rather

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76 Exh. JCCAs-1 at 41:20 to 42:2.

77 Exh. PG&E-4 at 20:16 to 23:11.

78 Exh. JCCAs-1 at 42:5-6.

79 *Id*. at 42:3-5.

80 D.20-02-047, p. 11.

than the ERRA), stating "The year-end balance in this subaccount is returned, in its entirety with interest, through a transfer to the applicable vintage subaccount of the PABA."[81] Despite the Joint CCAs raising the issue in direct testimony,[82] PG&E does not address SCE's approach in rebuttal, providing no justification for why the two utilities should have differing approaches. PG&E should be required to follow an approach similar to SCE's approach to ensure recently departed customers are treated fairly.

Lastly, PG&E raises the issue that this question could be addressed "upon the Commission authorization of a rate change in the [PUBA] Trigger Application."[83] No scoping ruling has been issued for PG&E's PUBA Trigger Application, A.20-09-014. While the PCIA Financing Subaccount appears to be part of PG&E's overall revenue requirement request in that case, no party has expressly called for this issue to be addressed specifically as part of that case, and PG&E did not address the issue in the verifications attached to its application.[84] While coordination between the two proceedings is needed, if the issue is not resolved by the PUBA Trigger Application, the Commission should determine as part of this proceeding that the balance owed to bundled customers for PUBA financing should be refunded via PCIA rates.

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[81] Exh. JCCAs-1 at 42:10-14 (citing to SCE Advice 4084-E and SCE Preliminary Statement Section Q.3.b.).

[82] *Id*. at 42:3-14.

[83] *See id*., Attachment B, PG&E's response to Joint CCA DR 3.10.

[84] PG&E's proposal in the PUBA Trigger Application recommends a reduction to bundled customer rates in an amount equal to the PUBA balance (spread over bundled customer sales volumes). (*See* A.20-09-014, p. 2.) Such an approach would address some, but not all, of the PCIA Financing Subaccount.

B. Issues Related to PG&E's GTSR Proposals.

1. PG&E Miscalculated the Resource Adequacy Component of GTSR and ECR Rates.

The Resource Adequacy charge calculated within PG&E's proposed GTSR and ECR rates is unjust, unreasonable and not in compliance with D.15-01-051. The RA charge should be revised such that the rate reflects, as directed, the costs and load for only bundled customers, which requires adjustments to both the numerator and denominator in PG&E's calculations. Correcting PG&E's calculation increases the RA charge for E-GT and E-ECR from $0.00798/kWh to $0.01312/kWh.

PG&E presents its calculation of the GTSR and ECR rates in Chapter 13 of its Prepared Testimony and corresponding workpapers,[85] which show that the RA charge is calculated by converting the RA Adder, which is a $/kW-month value, into a $/kWh charge. First, the RA charge uses the same RA Adder used in the PCIA calculation elsewhere in the instant Application to calculate the Retained RA value included in the Indifference Amount.[86] Since the RA Adder is typically expressed in terms of $/kW-month, PG&E converts the $/kW-month value to a cents-per-kWh charge by multiplying the RA Adder by the net qualifying capacity ("NQC") of its PCIA-eligible generation resource portfolio to get a total cost, *i.e.*, "the numerator."[87] It then divides that total cost by the <u>*entire*</u> annual retail load from both PCIA-eligible bundled *and* unbundled customers, *i.e.*, "the denominator."[88] The resulting cents-per-kWh rate is then included in the E-GT and E-ECR rates as the Resource Adequacy charge.[89] PG&E's

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85 Exh. JCCAs-1 at 45:8-10.

86 *Id*. at 45:13-15; Exh. JCCAs-14-C (sheet "RA Adder").

87 *Id*. at 45:15-17.

88 *Id*. at 45:17-18.

89 *Id*. at 45:18-20.

methodology underestimates the RA cost component of serving GTSR and ECR customers by nearly 40%.[90]

D.15-01-051 set the methodology for determining the cost of RA provided to bundled customers. Important to the RA charge calculation, that decision found that "[t]he utilities must charge all bundled customers, *including GTSR customers,* for the value of RA procured *on their behalf*."[91] Guided by that principle, the decision adopts the RA Adder as a reasonable proxy for calculating the cost of procuring RA for GTSR customers.[92] It then states in its Findings of Facts: "To determine the RA charge, it is reasonable to multiply the RA value from the annual PCIA calculation by *the amount of RA procured on behalf of the GTSR customer*, assuming 15% reserve margin."[93]

As PG&E stated in response to discovery, "Decision 15-01-051 approved the RA Adder used in the PCIA OIR to determine the market value of capacity of the utility retained generation portfolio stating that: 'We agree with the IOUs and other parties that the RA adder from the annual PCIA calculation is reasonable, fair, and consistent with SB 43. In addition, we agree with SCE that the amount of RA allocated to GTSR customers should take into account the 15% reserve margin.'"[94] However, D.15-01-051 makes no other findings in terms of how to calculate the RA charge in calculating GTSR customer rates, meaning the decision only expressly

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90 *Id*. at 46:9-11.

91 D.15-01-051 at 105, Conclusion of Law 52 (stating "GTSR customer rates should require GTSR customers to be responsible for costs incurred on their behalf, including renewable integration costs, provided that the IOU does not already cover the cost through a different mechanism.") (emphasis added); *see also* Exh. JCCAs-8.

92 D.15-01-051 at Findings of Fact 102.

93 *Id*. at Findings of Fact 103 (emphasis added).

94 Exh. JCCAs-8 (citing to "D.15-01-051, p. 107.")

addresses the numerator and not the denominator.[95] Guidance on the kilowatt-hours of load that should be included in the denominator is limited to the principle of aligning the customers in the denominator with the resources (in the numerator) with which PG&E will serve those customers.

PG&E's methodology contravenes D.15-01-051 by calculating the RA charge from too broad of a pool of both resources and customers and creating a mismatch between the resources included in the calculation and the customers those resources serve. [96] The error requires revisions in both the numerator and the denominator of PG&E's rate calculations. Within the numerator, PG&E correctly uses the RA Adder.[97] However, it then multiplies the RA Adder by the NQC of the <u>*entire*</u> PCIA-eligible generation resource portfolio to get the total cost. [98] That is, PG&E calculates the numerator using capacity that is not just procured on behalf of bundled customers, as required by D.15-01-051, but rather by using all PCIA-eligible capacity in the utility's portfolio, including the substantial amount of capacity PG&E sells to other load-serving entities.[99] To address this error, the RA Adder should have been multiplied by only the Retained RA to serve bundled load as reported in PG&E's Chapter 9 workpapers.[100] By the definition provided in D.19-10-001, Retained RA is the RA capacity procured on behalf of bundled customers.[101] The PCIA-eligible portfolio is far from the *total* portfolio that serves the entire PCIA-eligible load—it is only the PG&E-owned share.

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95 *See id*. (where PG&E describes how discussion of the RA charge in that decision addressed arguments on whether the RA Adder should be used).

96 Exh. JCCAs-1 at 46:1-2.

97 *Id*. at 45:15-17.

98 *Id*.

99 *See id*.; *see also id*. at 19:3-12 (describing the difference between Retained, Sold and Unsold RA).

100 *Id*. at 46:13-15.

101 D.19-10-001 at Ordering Paragraph 2, Attachment B, Table II.

The denominator must also be revised to bring PG&E's calculation in line with D.15-01-051. In response to discovery, PG&E admitted it calculates the denominator based on "bundled, CCA, and non-exempt direct access customers."[102] In order for "bundled customers, including GTSR customers" to be charged based on the RA capacity "procured on their behalf," the denominator should consist of only PG&E's bundled customers, including GTSR customers. Doing so ensures the customers in the denominator match the resources in the numerator.[103] If both the changes to the numerator and the denominator are made, the RA charge for E-GT and E-ECR increases from \$0.00798/kWh to \$0.01312/kWh.[104]

PG&E's rebuttal testimony takes no issue with the Joint CCAs' rate calculations but stretches to suggest *dicta* in D.15-01-051 supports what it describes as a system-based RA Charge calculation.[105] However, there is no "mandate from D.15-01-051 to value the total portfolio capacity value,"[106] as PG&E suggests, and, even if there was, PG&E's methodology does not meet that standard by failing to account for all non-PG&E procurement that takes place in its service territory.

The only three conclusions of law and findings of fact in D.15-01-051 relevant to calculating the RA charge are that (1) GTSR customers are responsible for costs procured on their behalf; (2) that the RA Adder should be used to calculate the RA Charge; and (3) that "to determine the RA charge," it is reasonable to multiply the RA Adder by "the amount of RA

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102 *See* Exh. JCCAs-12.

103 Exh. JCCAs-1 at 46:16-18.

104 *Id*. at 46:15-19.

105 *See* PG&E Rebuttal at 24:9-25:9.

106 *Id*. at 26:14-15.

procured on behalf of the GTSR customer."[107] While PG&E's non-attorney witness makes much of a reference to the Transitional Bundled Commodity Cost ("TBCC") in D.15-01-051, and to other parties' proposals in that case, the only purpose of those discussions in the decision is to support the adoption of the RA Adder as a proxy for RA value.[108] In the citation PG&E itself quotes in its testimony, the Commission stated: "[The PCIA's RA Adder] calculates the short-term capacity value of PG&E's total portfolio. This same calculation methodology is used to set the capacity adder used in the TBCC rate."[109] The decision never links the TBCC to the RA charge with regard to what resources should be included in the numerator or what billing determinants should be used in the denominator. The only relevant findings limit the calculation of the RA charge to the value of RA procured on *bundled customers*' behalf,[110] which is the exact opposite of the system-level approach PG&E uses in its calculation.

Tellingly, PG&E admits in its Rebuttal Testimony that it unilaterally departed from the TBCC method of calculating a rate for RA value which requires the portfolio value to be divided by the total portfolio generation output.[111] PG&E attempts to justify its proposed RA charge calculation by arguing that dividing by generation is "an imperfect calculation for determining customers rates."[112] However, PG&E only implemented this change in the calculation of the RA charge, not the RA *credit* for GTSR resources. PG&E calculates the RA *credit* by dividing the

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107 D.15-01-051 at 105, Conclusion of Law 52, Findings of Fact 102 and 103.

108 Exh. PG&E-4 at 24:7-9, 25:9 to 26:29.

109 D.15-01-051 at 106; PG&E Rebuttal at 23:17-21.

110 D.15-01-051 at 105, Conclusion of Law 52, Finding of Fact 102 and 103.

111 Exh. PG&E-4 at 25:31 to 26:9.

112 PG&E Rebuttal at 26:5.

RA value of GTSR resources by the expected generation output, creating an additional inconsistency within the GTSR tariff rate calculation.[113]

Moreover, even if D.15-01-051 had adopted a system-level approach to calculating the RA charge, PG&E's calculations do not include system-level capacity in its calculations; only system-level customers. CCAs in their service territory are responsible to independently procure capacity to comply with their individual RA requirements, and CCAs in PG&E's service territory meet their RA obligations by procuring RA resources, at least in part, from counterparties other than PG&E.[114] However, PG&E's "system-wide" calculations do not include any non-PG&E resources. At the same time, PG&E did calculate an RA charge that includes system-wide customers, thereby increasing the denominator and resulting in a lower RA charge.

PG&E's methodology artificially depresses the cost of providing RA to bundled customers on those rates and creates an unfair competitive advantage, falsely suggesting its GTSR rate—the rate PG&E uses to compete with 100% clean CCA rates—includes a lower cost for RA than that of the CCAs. The RA charge calculated within PG&E's proposed GTSR and ECR rates is unjust, unreasonable, not in compliance with all applicable rules, regulations,

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113 If PG&E calculates the RA charge the same as the RA credit (i.e. *total portfolio* RA value / portfolio generation), the rate would be between \$11-\$13/MWh (similar to what the JCCAs have proposed here). *See* Exh. JCCAs-14-C and 15-C.

114 *See* Cal. Pub. Util. Code §§ 366.2(a)(5) ("A [CCA] shall be solely responsible for all generation procurement activities on behalf of the [CCA's] customers, except where other generation procurement are expressly authorized by statute."), 380 (subjecting CCAs to resource adequacy requirements); D.20-06-022, p. 37 (explaining the Commission's responsibility to ensure resource adequacy regardless of which load serving entity offers service.); D.20-06-031 (adopting load-serving entities' local capcity obligations for 2021-223 and adopting flexible capacity obligations for 2021). When asked to confirm it as part of this case, PG&E objected and stated "PG&E does not know how each CCA in its service territory meets its RA obligations nor does PG&E have knowledge of all CCA counterparties." Exh. JCCAs-9; Exh. JCCAs-10. PG&E's professed ignorance of how LSEs meet RA requirements in its service territory aside, any number of CCA RA compliance documents submitted to the Commission would confirm this fact.

resolutions and decisions for all customer classes, and must be rejected in favor of the JCCA-calculated rates.

2. PG&E Should Include Funding for CCAs' Offerings of Disadvantaged Community Solar Programs in its 2021 Budget Proposal, Funded in Whole or in Part from GHG Allowance Revenues.

PG&E's proposals for the 2021 disadvantaged community green tariff ("DAC-GT") and community solar green tariff ("CS-GT") programs are unjust and unreasonable and inconsistent with D.18-06-027 and D.19-02-023 because they do not include pending funding requests for CCA programs. Both the PG&E and CCA programs are to be funded initially from the state's greenhouse gas ("GHG") allowance auction proceeds fund, up to the total allocated by the Commission decisions, with the residual amount to come from Public Purpose Program ("PPP") funds.[115] While the CCA budgets for 2021 have not yet been approved, the Commission determined in a prior ERRA Forecast proceeding that silence with regard to pending budgets for the DAC-GT and CS-GT programs in the following year is inconsistent with the decision authorizing them, D.18-06-027.

D.18-06-027 authorized CCAs to offer DAC-GT and CS-GT programs that draw from the same funding sources as PG&E's programs:[116]

> *[W]e find that it is reasonable to use a portion of the proceeds from the sale of GHG allowances as the primary funding source for both the DAC-SASH and DAC-Green Tariff programs. As MCE notes, GHG auction proceeds are intended to benefit both bundled and unbundled customers. Consistent with this, it is reasonable for CCA customers to be eligible for a comparable CCA DAC-Green Tariff.*

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115 Exh. PG&E-1 at 17-5; Exh. JCCAs-1 at 48:7-9.

116 D.18-06-027 at 55-56 ; *see also id.* at Finding of Fact 37, Conclusion of Law 30, and Ordering Paragraph 17.

Resolution E-4999 implemented D.18-06-027's framework.[117] The resolution reserved capacity for CCAs based on the proportionate share of service area residential customers located in a disadvantaged community,[118] and allows CCAs to share and trade these allocations to make the programs financially more feasible.[119] Two CCAs, MCE and EBCE, have now filed advice letters to establish and implement their respective DAC-GT and CS-GT programs.[120] Three other CCAs are currently planning to file advice letters by November 2020 and others may do so by January 1, 2021.[121]

Chapter 17, Section C, of PG&E's Prepared Testimony describes its proposed funding for its disadvantaged community solar programs, which include its DAC-GT and CS-GT programs that the Commission has also authorized CCAs to administer.[122] PG&E includes its budget for its DAC-GT and CS-GT programs in its revenue requirement request,[123] but it does not include the budget for the CCAs' programs.[124]

To be consistent with D.19-02-023, CCAs' program budgets that have been proposed in advice letters pending Commission resolution should be determined concurrently with that of

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117 Res. E-4999 at 5-6.

118 *Id*. at 12-14, Findings and Conclusions ¶ 16.

119 *Id*. at 16, Findings and Conclusions ¶ 17.

120 Exh. JCCAs-16 (Supplement to MCA Advice Letter 42-E, including budget of $$1,853,437); EBCE, Advice Letter 14-E, September 11, 2020 (including budget of $984,921.53 in Appendix C). MCE filed its supplemental Advice Letter due to changes to the enrollment mechanism under DAC-GT. As a result, the budget was adjusted down to $1,853,437. *See id.*

121 Exh. JCCAs-1 at 49:4-5(noting these CCAs include PCE, SJCE, and CPSF).

122 *Id*. at 48:7-9.

123 Exh. PG&E-1 at 17-12:11 - 17-13:27. The GHG Allowance Revenue Return comes from the California Air Resources Board's Statewide Cap and Trade Program Allowance Auction and the Public Purpose Program rate components are determined in PG&E's General Rate Case

124 Exh. JCCAs-1 at 49:9-11.

PG&E.[125] Importantly, a question yet to be addressed by the Commission, raised in part by PG&E's inclusion of these programs in this ERRA Application, as opposed to a separate funding request, is how CCAs and PG&E can access additional funding through the PPP and how the Commission will allocate the GHG Allowance and PPP Funds to PG&E and the CCAs administering their own programs, given that all 2021 GHG revenues are likely to be exhausted by both PG&E and the CCAs' requests.[126] Since all budgets draw from the same pool of GHG revenues, and since all budgets will apply to the 2021 forecast year, a Commission determination is needed now to provide a pathway to fully funding all programs. This determination should direct PG&E to allocate the GHG revenue and PPP funding proportionately among PG&E and CCA administered DAC-GT and CS-GT programs.

For this reason, the Joint CCAs requested in their Direct Testimony that PG&E include in its November Update the funding for eligible CCA programs for which the requisite advice letters have been filed, with a specification of how the funding sources are allocated across those programs.[127] PG&E has refused to do so without Commission direction,[128] thereby clouding the implementation and cost recovery from these important DAC programs.

PG&E's sole justification for refusing to include at least a placeholder for these CCA programs is that the CCAs' advice letters have not yet been approved.[129] The shortcoming in this position is that PG&E's own program funding was in the same procedural position as the CCAs' programs during the 2019 ERRA forecast case when PG&E similarly opted to exclude its

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125 *Id*. at 49:12-13.

126 *Id*. at 49:6-9.

127 *Id*. at 49:13 to 15:2.

128 Exh. PG&E-4 at 29:3-23.

129 *Id*.

proposed funding as a set-aside for 2019 forecasted GHG revenues.[130] The Commission rejected that approach in D.19-02-023. That decision determined that "PG&E's silence regarding a set-aside for the DACGT and CSGT programs is inconsistent with D.18-06-027."[131] The Commission then determined to set aside the remainder of PG&E's unallocated funding for Clean Energy and EE projects under the GHG allowance revenues ($14.499 million) for funding PG&E's DAC-GT and CSGT programs in 2019.[132] This allowed PG&E to access GHG allowance revenues for cost recovery under the DAC-GT and CS-GT programs even though their Implementation Advice Letter, 5362-E, was still pending with the Commission.[133]

The same opportunity must be afforded to CCAs implementing the DAC-GT and CS-GT programs. PG&E should include the program budgets for MCE and EBCE of $1,853,437 and $984,922, respectively, in its November Update testimony with a proposal on how to timely allocate funds between the pool of funding from GHG revenues and the PPP—this should include an opportunity for CCAs to gain access to a proportionate share of the GHG revenues for 2021.[134]

C. A Consistent, Formal Approach to Increasing the Transparency of PG&E's Forecasted Year-End PABA Balance is Needed.

The Commission should not set PCIA rates based solely on unverifiable assertions of an estimated year-end PABA balance for which no volumetric data have been provided in support. When Chapter 14 is boiled down, the extent of PG&E's support in its Prepared Testimony for the year-to-date component of it forecasted year-end PABA balance of $537.1 million is an

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130 *See* D.19-02-023 and JCCAs-13.

131 D.19-02-023 at 11.

132 *Id*. at 10 and Conclusion of Law 1.

133 *See* PG&E Advice Letter 5362-E, filed on August 20, 2018, as supplemented by Advice Letter 5362-E-A (February 13, 2019), and approved by Resolution E-4999 on June 3, 2019.

134 *See* n. 120, *supra*, regarding the update to MCE's requested budget.

assertion that it is based on recorded values through April.[135] PG&E provides Table 14-2, which includes few details regarding this under-collection, simply listing dollar totals by vintage for major categories of costs and revenues.[136] The utility also describes some factors it believes are influencing the PABA balances but provides no data allowing verification of those factors.[137] Finally, it promises to update this data in its November Update,[138] which will provide recorded values through September with a similar level of vagueness.

While PG&E has made progress on transparency since the one line of data it originally offered to support the PABA balance in last year's ERRA forecast prepared testimony, none of what PG&E provides in either its testimony or its workpapers ensures errors were not made or that parties can understand with confidence the factors that will influence both the November Update and the final 2021 PCIA rates.[139] Since the balances PG&E presents are unverifiable, its Prepared Testimony alone does not meet its burden to support its requested relief with substantial evidence, and it cannot be determined from PG&E's testimony alone that the utility has proposed just and reasonable rates. The lack of volumetric data prevents the Joint CCAs from verifying PG&E's description of the elements driving the under-collection. It also prevents CCAs in PG&E's service territory from being able to plan for 2021 rate changes without substantial discovery, and creates the potential for an unnecessarily controversial and contested November Update.

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135 Exh. PG&E-1 at 14-8:1 to 14-10:8; Exh. PG&E-4 at 14:18-19.

136 Exh. PG&E-1 at p. 14-9, Table 14-2.

137 *Id*. at 14-10:9 to 14-12:18, 14-14:14 to 14-16:13.

138 *Id*. at 14:20:4-11.

139 *See* Exh. JCCAs-1 at 31:4 to 34:8.

The Commission should also note that the Joint CCAs raised similar issues in the 2020 ERRA Forecast application about the recorded and forecasted 2019 PABA balance to be included in the 2020 PCIA rates. In the 2019 ERRA Compliance proceeding, PG&E in fact has conceded that it made at least $130 million in erroneous errors and another $70 million in dispute. As a result, departed load customers must wait an additional year for the reduction in the PCIA rate that they would have received in 2020 if PG&E's PABA balance forecast had received the scrutiny that the law requires. Absent reasonable verification of PG&E's balances in this proceeding, the Commission risks allowing similarly costly and avoidable errors to go uncorrected.

As outlined in the Scoping Ruling, the reasonableness of PG&E's requested $2.8 billion PCIA revenue requirement includes consideration of whether the calculations and entries used to produce that request are "in compliance with all applicable rules, regulations, resolution and decisions for all customer classes," and whether the resulting rates should be approved.[140] The Commission also cannot grant the relief requested in PG&E's Application based merely on uncorroborated, disputed evidence.[141] The Commission, therefore, must require PG&E to support its assertions with sufficient evidence or reject the components of PG&E's Application unsupported by substantial evidence.

In response to assertions in the Joint CCAs' direct testimony that it has presented unverifiable data, PG&E cites to D.20-02-047 and suggests the data it provided via discovery – along with a promise to continue to do so – is sufficient. PG&E states that "the ERRA Forecast

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[140] Scoping Ruling at 2 (Scoping Items d and e).

[141] Cal. Pub. Util. Code § 1757(a)(4). *See, e.g., The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (February 5, 2014).

proceeding is not the platform to review the recorded PABA balance."[142] However, D.20-02-47 does not go as far as PG&E suggests, and with good reason. The body of that decision states: "PG&E's use of recorded data through September 2019, plus a forecast of the remaining three months is appropriate and sufficient for its forecast." [143] As PG&E notes in rebuttal, the decision also states that "review of the PABA recorded balance is to occur within the ERRA Compliance Review proceeding and not the ERRA forecast."[144] The Joint CCAs' request for more transparency in this proceeding does not encroach on either finding.

That is, D.20-02-047 does not prevent *any and all* review of the data recorded to PABA in 2020 from taking place within this proceeding—the decision just sets the forum for the final review of the PABA balance, which the Joint CCAs do not dispute. While the Joint CCAs agree that a detailed audit of PABA, such as that contemplated in Ordering Paragraph 8 of D.18-10-019, is better suited to the scope and timelines of PG&E's ERRA compliance proceeding, both the Scoping Ruling and the law require some review of verifiable data as part of this proceeding in order to ensure rates are just and reasonable. Decision 20-02-047 should not be read, as PG&E's Rebuttal Testimony could be read to suggest, that *any* amount the utility records to PABA *must* be approved by the Commission. That could lead to absurd results that would not be challengeable under PG&E's framework. For example, if a party discovered PG&E made a $200 million error in its recorded actuals, or even that PG&E simply failed to multiply a value by 1,000 by mistake in its workpapers (as it did in the 2020 ERRA Forecast Workpapers), the party would not be allowed to raise the issue on the record yet, unquestionably, the resulting PCIA

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142 Exh. PG&E-4 at 17:13-16.

143 D.20-02-47 at 12.

144 Exh. PG&E-4 at 17, n. 35; D.20-02-47 at 12.

rates would not be just and reasonable. Worse, if disputed by PG&E, the error would not be fixed in rates until at least Q1 2023, once PG&E's 2021 ERRA compliance case would conclude.

A high-level review of the projected year-end PABA balance is necessary as part of this proceeding to ensure rates are just and reasonable. In addition to recorded and projected PABA dollar amounts, the underlying volumetric data are the substantial evidence not only needed to conduct such a review but also to allow the Commission to grant PG&E's requested relief. Large deviations between actual and forecasted results spotlight potential areas for investigation.[145] Often such investigation leads to the discovery of errors or opportunities to improve forecasts, all of which is in the interest of both bundled and unbundled customers.[146]

As PG&E notes in rebuttal, the Joint CCAs sought the utility's cooperation in the discovery process to provide monthly actual volumetric data, by category, underlying the PABA actuals in this proceeding.[147] The Joint CCAs were finally provided some volumetric data underlying the recorded PABA balances on September 17, 2020, more than two months after the Application was made, nearly two months after the July 20, 2020 request for such data was originally made, and only one week prior to the deadline for filing intervenor testimony.[148] The data eventually provided is useful, and allowed for some last-minute, high-level analysis, but it is still summarized in a way that prevents a review of each resource category and the impact on PCIA rates in this Application.[149]

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145 Exh. JCCAs-1 at 25:13-14.

146 *Id*. at 25:14 to 26:2.

147 Exh. PG&E-1 at 32:18-20.

148 Exh. JCCAs-1 at 32:20 to 33:1; Exh. PG&E-4 at 14:25 to 15:23, 16:2, and 18:24; Scoping Ruling at 4.

149 Exh. JCCAs-1 at 33:1-2; Exh. PG&E-4 at 15:24 to 16:13.

Moreover, the discovery process is not an ideal avenue in which to obtain this data given the abbreviated schedule required in the ERRA forecast proceeding.[150] The ERRA forecast proceeding simply cannot accommodate the timeframe necessary for the elements of a protracted discovery dispute, *i.e.*, the objections, need to meet and confer, and potential need for the Commission to resolve a motion to compel. PG&E only agreed to provide the data here after a lengthy and contentious discovery dispute. As noted, nearly two months passed between the CCAs July 20, 2020 original data request and the final supplement to PG&E's first responses were sent on September 17, 2020.[151]

Further, at every step, PG&E persistently and consistently only offered the data subject to objection,[152] which leaves substantial questions surrounding whether the data – and any testimony relying on it – will be admitted into the record. Such objections were even included with regard to requests for updated data on specific proposals the IOU made with regard to Unsold RA that *depend entirely on recent PABA volumetric data*.[153]

While PG&E repeatedly belittled the Joint CCAs' valid requests for more data and transparency as "complaining" throughout its rebuttal testimony,[154] the fact remains that the JCCAs and the Commission benefit from such data. Transparent and timely access to data can reduce conflict in the ERRA proceedings, minimize unexpected outcomes in the November Update, and facilitate timely resolution of the annual ERRA proceedings.[155] The best way to

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[150] Exh. JCCAs-1 at 33:3-4.

[151] Exh. JCCAs-1 at 32:20 to 33:1; Exh. PG&E-4 at 14:25 to 15:23, 16:2, and 18:24; Scoping Ruling at 4.

[152] *See, e.g.,* Exh. PG&E-4 at Appendix B (PG&E Supplemental Responses to Joint CCAs' Data Request 2.03); Exh. JCCAs-4; Exh. JCCAs-11.

[153] *See* Exh. JCCAs-4.

[154] *See, e.g.,* Exh. PG&E-4 pp. 14-19.

[155] Exh. JCCAs-1 at 32:12-14.

meet PG&E's oft-repeated interest in having rates in place on January 1 is to provide – *upfront* – to parties the data needed to have confidence the proposed 2021 rates are just, reasonable and appropriately calculated.

As customer-facing load serving entities, it is imperative CCAs are granted access to the data required to complete their analyses on a timely basis in order to anticipate and plan for potential rate impacts on their customers and to operate their own programs to serve their customers.[156] PG&E is the Joint CCAs' main competitor, and the CCAs cannot simply wait for PG&E's November Update, take the utility's word for it that the rates are correct, and hope for the best on January 1, particularly in light of material errors the Joint CCAs have been able to identify in past ERRA forecast applications. The true-up adopted in D.18-10-019 married the PCIA rates CCA customers pay to PG&E's data to the foreseeable future. Without timely and detailed access to recorded data as part of this proceeding, there is an unequal playing field between PG&E's ability to plan for January 1, 2020 rate increases and CCAs' ability to plan for those same rate increases. This unequal playing field creates unnecessary conflict, especially surrounding the November Update. While the JCCAs appreciate the modest progress toward equal access accomplished in this proceeding, PG&E's persistent objections, delays in providing responses, and continuing hostility towards more transparency make clear that formal action is required.

Consistency in the data provided from one ERRA forecast proceeding to the next, and and from the ERRA forecast proceeding to the subsequent ERRA compliance proceeding, and consistency in the data provided to CCAs throughout California by one IOU compared to that provided by another IOU, also warrant formal action by the Commission. It is for this reason

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[156] *Id*. at 32:14-17.

CCAs in both SCE and SDG&E's ERRA Forecast proceedings have made the exact same request as that presented in this case.[157] Namely, in future ERRA forecast applications, PG&E and the other IOUs should be required to provide in their confidential workpapers, and in routine updates throughout the proceeding, the data required to review actual PABA activity. Such data should include:[158]

- Confidential versions of the monthly ERRA/PABA/PUBA reports.
- Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as UOG costs and Contracts (e.g. provide by resource type, and whether RPS or non-RPS eligible).
- Actual volumetric quantities underlying each relevant dollar figure; such categories include UOG generation, power purchases and sales, CAISO market sales, and retail customer sales.
- Monthly volumes of Actual Sold, Retained, and Unsold RA.
- Monthly volumes of Actual Sold, Retained, and Unsold RPS.

Without supporting data, including volumetric quantities underlying recorded costs and revenues, it is not possible to say, in a reasonably timely manner, whether PG&E's PABA balance is reasonable; it requires substantial discovery for CCAs to simply understand the market forces underlying those amounts; it is difficult for CCAs to plan for the likely rate changes that will result until it is too late, *i.e.*, after the November Update; and it results in an unnecessarily contentious and controversial November update that likely leads to either due process concerns

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[157] *See id.* at 33:3-17; A.20-04-014, *Opening Brief of San Diego Community Power and Clean Energy Alliance*, p. 9 (September 25, 2020); A.20-7-004, *Joint Opening Brief of the Clean Power Alliance and California Choice Energy Authority and the California Community Choice Association*, pp. 15-16 (October 26, 2020).

[158] Exh. JCCAs-1 at 33:7-17.

or delayed PCIA rates. The solution to these problems is simply increased transparency, and there is no compelling argument against it.

V. ISSUES THAT WILL BE ADDRESSED IN THE JOINT CCAS' COMMENTS ON THE NOVEMBER UPDATE.

While certain issues have been resolved by parties' direct and rebuttal testimony, there is still a significant amount of work to be completed in this proceeding as part of the November Update. First, the revenue requirement requested in A.20-09-014, PG&E's PUBA Trigger filings, would amortize the entire projected year-end balance in PG&E's PUBA via a vintage-specific PUBA rate adder for departing load customers.[159] Therefore, PG&E's request "that any year-end PUBA balance not disposed of via an expedited application process be included in the PCIA revenue requirement for recovery as part of its November Update" appears to be moot.[160] In addition, concerns over an immediate trigger in 2021 would also be resolved.[161]

However, as part of a joint protest with CalCCA to A.20-09-014, the JCCAs have suggested not only that the PUBA year-end balance be amortized over three years,[162] but also that such an amortization should accompany a suite of modifications to the PCIA framework, potentially including the removal of the PCIA rate cap in 2021, aimed at avoiding (1) complexities in tracking different vintages of PUBA balances, (2) the potential for multiple

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159 A.20-09-014, *Expedited Application of Pacific Gas and Electric Company Under the Power Charge Indifference Adjustment Trigger*, p. 2 (September 28, 2020).

160 Application at 8; Exh. Joint CCAs-1 at 42:15 to 45:4.

161 Exh. Joint CCAs-1 at 44:12 to 45:4.

162 A.20-09-014, *Joint Protest of CalCCA and the Joint CCAs to the Expedited Application of Pacific Gas and Electric Company Under the Power Charge Indifference Adjustment Trigger Mechanism*, pp. 6-11 (October 19, 2020) ("Trigger Protest").

trigger applications in the same year, and (3) the likelihood of a never-ending cycle of trigger applications.[163]

One component in that suite of modifications would be to amortize the entire PCIA revenue requirement resulting from this proceeding over three years in addition to the 2020 PUBA balance.[164] Establishing such an amortization would eliminate the potential for a PUBA trigger in 2021.[165] By addressing the entire 2021 PABA balance and avoiding capped rates in 2021, there will be no PUBA Differential and no balance accruing to PUBA in 2021 from the 2021 PCIA revenue requirement.[166] Avoiding a trigger in 2021 would allow the Commission and stakeholders to pursue more permanent solutions to the rate volatility caused by the implementation of the PABA true-up and the cap-and-trigger mechanism.[167] The proposal would result in the effective 2021 PCIA rates listed below in Table 4 from the joint protest:[168]

Table 4: Effective PCIA Rates – Uncapped 2021 PCIA Rates Plus PG&E's Proposed PUBA Adder (36-month Amortization for Both)

	Combined 2021 PCIA Rates + PUBA Rate Adder											
Rate Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	0.03121	0.03618	0.03837	0.03981	0.04048	0.04090	0.04073	0.04077	0.04086	0.04078	0.03950	0.03891
Small L&P	0.03002	0.03480	0.03691	0.03830	0.03894	0.03934	0.03918	0.03922	0.03930	0.03924	0.03798	0.03739
Medium L&P	0.03217	0.03729	0.03955	0.04104	0.04173	0.04216	0.04199	0.04203	0.04211	0.04204	0.04072	0.04013
E19	0.02954	0.03425	0.03632	0.03769	0.03832	0.03872	0.03856	0.03859	0.03868	0.03861	0.03739	0.03683
Streetlights	0.02488	0.02883	0.03058	0.03173	0.03227	0.03260	0.03247	0.03250	0.03256	0.03251	0.03149	0.03102
Standby	0.02253	0.02612	0.02770	0.02874	0.02923	0.02953	0.02941	0.02944	0.02950	0.02945	0.02852	0.02811
Agriculture	0.02791	0.03235	0.03431	0.03560	0.03620	0.03657	0.03643	0.03646	0.03654	0.03647	0.03532	0.03480
E20 T (Excluding FPP)	0.02536	0.02940	0.03118	0.03235	0.03290	0.03323	0.03310	0.03313	0.03320	0.03314	0.03209	0.03162
E20 P (Excluding FPP)	0.02726	0.03160	0.03352	0.03478	0.03536	0.03573	0.03558	0.03561	0.03569	0.03563	0.03451	0.03401
E20 S (Excluding FPP)	0.02850	0.03304	0.03504	0.03636	0.03697	0.03735	0.03720	0.03723	0.03731	0.03725	0.03606	0.03550
System Average PCIA Rate by Vintage	0.02976	0.03450	0.03659	0.03797	0.03861	0.03901	0.03885	0.03888	0.03897	0.03890	0.03768	0.03731
% Increase vs. Current Rates	22%	26%	23%	28%	22%	22%	22%	22%	23%	23%	11%	NA

Clearly, if the CCAs' proposal is adopted in A.20-09-014, it would impact the PCIA rates adopted within this proceeding. In addition, the rates in Table 4 above were developed based on

163 Trigger Protest at 11.

164 *Id*. at 13.

165 *Id*. at 14.

166 *Id*.

167 *Id*.

168 *Id*.

PG&E and the Joint CCAs' testimony to date in this proceeding and would need to be updated as a result of the new data presented in PG&E's November Update. With such data in hand, the JCCAs will present as part of their comments on the November Update a full accounting of the impacts of their proposal in A.20-09-014 on the rates to be adopted in the instant proceeding.

Beyond the impact of the PUBA trigger on the instant application, the following issues will also be addressed in the JCCAs' comments on the November Update:

- PG&E's forecast for Unsold RA in 2021, which is currently zero MW.[169]
- Updating the GTSR and ECR rates discussed in Section IV.C.2 of this Opening Brief based on the revised RA Adder for 2021.
- PG&E's October 26, 2020 updated load forecast, related to the on-going pandemic.[170]

Finally, the Joint CCAs reserve their right to address these issues, modify the recommendations within this Opening Brief, and address any other issues presented in PG&E's November Update via the JCCAs' comments on the November Update, or any further process the Commission may adopt.

VI. UNCONTESTED ISSUES.

PG&E and the Joint CCAs have resolved certain issues through direct and rebuttal testimony

- Approved General Rate Case Revenue Requirements: PG&E's proposed PCIA rates were based on the proposed generation costs from PG&E's pending 2020 Phase I GRC, A.18-12-009, which has not yet been finalized or approved by the Commission.[171] Until the Commission has issued a final decision in that case, PG&E

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[169] Exh. JCCAs-1 at 10-12 (citing to Exh. PG&E-1 at 9-4:7 and n.13); Exh. PG&E-4 at 10:17 to 11:22.

[170] *See* Exh. PGE-5 At 1:12-16 (explaining the update is to address "changes to PG&E's load forecast due to impacts from the novel coronavirus global pandemic (COVID-19) that were unavailable on July 1, 2020 when PG&E served its opening Prepared Testimony.")

[171] Exh. JCCAs-1 at 16:10-13 and Attachment B, PG&E Response to Joint CCAs DR 2.13. A proposed decision was issued in A.18-12-009 on October 23, 2020.

has agreed to include the generation base revenue requirement approved in D.17-05-013, as adjusted for tax reform, in the calculation of the Indifference Amount, reducing the Indifference Amount by $104.7 million.[172]

- Unapproved Wildfire Expense Memorandum Account Costs: Likewise, PG&E's request to recover $498.7 million of insurance costs recorded in the WEMA, commencing in January 2021, is currently also unapproved.[173] PG&E agreed to remove the generation-related WEMA costs from PG&E's calculation of the Indifference Amount, reducing the PCIA revenue requirement in this case by $131.1 million.

- Forecast Retained RA Adjustment: In response to Joint CCA DR 4.11 and in rebuttal testimony, PG&E confirmed that the capacity from six different contracts to purchase Local RA capacity was inadvertently omitted from the Retained RA volume and the associated Forecast Retained RA value, requiring a $5.2 million adjustment.[174] PG&E stated it would update this value as part of the November Update. [175]

- 2019 Retained RPS: After attempting to litigate this issue for the *fourth time*, after it was first resolved as part of last year's ERRA forecast case,[176] PG&E agreed in rebuttal to include a $92.9 million adjustment for *2019* Retained RPS as part of the November Update, a reduction in the 2021 revenue requirement of $23.9 million.[177]

- CPE-Related Expenses: At the Joint CCA's request,[178] PG&E's rebuttal testimony clarified that the $16.5 million in requested administrative costs related to PG&E's new role as Central Procurement Entity ("CPE") were incremental to existing costs and that PG&E will not be allocating additional energy supply administration costs to the CAM for 2021.[179] That discussion resolves the Joint CCAs' concerns.

Changes to PG&E's requested relief on these issues, totaling over $250 million in adjustments to the utility's requested revenue requirement, should be reflected in the November Update.

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172 Exh. JCCAs-1 at 17:5 (including RF&U impact).

173 Exh. JCCAs-1 at 17:6 to 18:15 (citing to A.20-02-004, *Application of Pacific Gas and Electric Company (U 39 M) to Recover Insurance Costs Recorded in the Wildfire Expense Memorandum Account*, p. 1 (February 7, 2020)).

174 *Id*. at 19:1 to 20:3 and Attachment B, PG&E Response to Joint CCA DR 4.11; Exh. PG&E-4 at 10:4-16.

175 Exh. PG&E-4 at 10:4-16.

176 Exh. JCCAs-1 at 34:9 to 36:6.

177 Exh. PG&E-4 at 12:5-8; Exh. JCCAs-1 at 36:5-6.

178 Exh. JCCAs-1 at 46:20 to 47:2.

179 Exh. PG&E-4 at 28:10 to 29:2.

VII. CONCLUSION.

For the foregoing reasons, the Joint CCAs respectfully request the Commission:

- Refund the balance owed to recently departed bundled customers from the PCIA Undercollection Balance Account ("PUBA") Financing Subaccount via PCIA rates rather than ERRA rates;

- Reject PG&E's proposed GTSR and ECR rates, revising the RA charge within the rates to be $0.01312/kWh; and

- Include funding for CCA DAC-green tariff and ECR programs in the overall 2021 budget proposal for those programs.

- Order PG&E to provide monthly, aggregated volumetric data as part of its workpapers in future ERRA forecast proceedings because PG&E's current showing fails to meet the burden of proof.

The Joint CCAs reserve their right to modify these recommendations based on updated information presented in PG&E's November Update, and to address the numerous other issues likely to be raised therein, via comments on the November Update or any further process the Commission may adopt.

Respectfully submitted,

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