Community Advisory Committee Meeting
Monday, September 18, 2023
6:00 pm

<u>In Person</u>:
The Lake Merritt Room
Cal State East Bay - the Oakland Center
In the Transpacific Centre
1000 Broadway, Suite 109
Oakland, CA 94607

<u>Or from the following locations:</u>

- 4563 Meyer Park Circle, Fremont, CA 94536
- 3602 Thornton Ave, Fremont, CA 94536
- Castro Valley Starbucks - 2720 Castro Valley Blvd. Castro Valley, CA 94546
- Mountain House Library - 201 E. Main Street Mountain House, CA 95391
- 1743 140th Ave. San Leandro, CA 94578

<u>Via Zoom:</u>
https://us02web.zoom.us/j/84794506189

<u>Or join by phone</u>:
Dial(for higher quality, dial a number based on your current location):
US: +1 669 900 6833 or +1 346 248 7799 or +1 253 215 8782 or +1 929 205 6099 or +1 301 715 8592 or +1 312 626 6799 or 877 853 5257 (Toll Free)
Webinar ID: 847 9450 6189

Meetings are accessible to people with disabilities. Individuals who need special assistance or a disability-related modification or accommodation to participate in this meeting, or who have a disability and wish to request an alternative format for the meeting materials, should contact the Clerk of the Board at least 2 working days before the meeting at (510) 906-0491 or cob@ebce.org.

If you have anything that you wish to be distributed to the Committee, please email it to the clerk by 5:00 pm the day prior to the meeting.

C1. Welcome & Roll Call

C2. Public Comment

This item is reserved for persons wishing to address the Committee on any EBCE-related matters that are not otherwise on this meeting agenda. Public comments on matters listed on the agenda shall be heard at the time the matter is called. As with all public comment, members of the public who wish to address the Committee are customarily limited to three minutes per speaker and must complete an electronic speaker slip. The Committee Chair may increase or decrease the time allotted to each speaker.

C3. Approval of Minutes from July 17, 2023

C4. CAC Chair Report

A. **Al Weinrub**
B. **Staff Response to the Sustainability and Climate Action Plan City Staff and EBCE Coordination Report**
C. **CalCCA filing in the CPUC Diablo Canyon extension proceeding**
D. **Items not on the CAC agenda that are on the Board Agenda**
E. **MRP Incremental BESS**
   Consent to correct the record
F. **Energy Prepay #3 Summary**

C5. 2022 Power Source Disclosure Annual Report and Power Content Label (CAC Informational Item)

Requesting the Board to accept and attest to the 2022 Power Source Disclosure Report and Power Content Label

C6. CAC Structure per Ad Hoc Board Committee Recommendation (CAC Discussion Item)

Discussion of Restructure of CAC per Ad Hoc recommendation

C7. Update on Planning for Net Billing Tarriff (NBT) (CAC Informational Item)

Brief review of NBT planning and overview of status

C8. Inclusion of New Communities: City of Lathrop (CAC Action Item)

Consider City of Lathrop EBCE/JPA membership

C9. Update on Brand (CAC Informational Item)

Share logo, updated timeline, list of items that will change on 10/24, overview of how staff is supporting Muni-Pals

C10. Memorial Comments in Honor of Al Weinrub

C11. CAC Member and Staff Announcements including requests to place items on future CAC agendas

C12. Adjourn in honor of Al Weinrub

The next Community Advisory Committee will be held on Monday, October 16, 2023 at 6:00 pm.

Draft Minutes

Community Advisory Committee Meeting
Monday, July 17, 2023
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C1. Welcome & Roll Call

Present: Members Landry, Hu, Swaminathan, Lakshman, Pacheco, Lutz, Vice-Chair Hernandez and Chair Eldred.

Excused: Members Liu, Talreja and Souza

C2. Public Comment

This item is reserved for persons wishing to address the Committee on any EBCE-related matters that are not otherwise on this meeting agenda. Public comments on matters listed on the agenda shall be heard at the time the matter is called. As with all public comment, members of the public who wish to address the Committee are customarily limited to three minutes per speaker and must complete an electronic speaker slip. The Committee Chair may increase or decrease the time allotted to each speaker.

(2:31) Tom Kelly expressed his deep concerns about the escalating global temperature crisis, referencing recent record highs reported worldwide. He is contemplating opting out of EBCE due to his belief that the agency contributes to the global climate crisis. Additionally, he's considering pursuing legal avenues to ensure EBCE adheres to its JPA obligations. Mr. Kelly urged the committee to explicitly communicate their actions in response to his repeated concerns, seeking clarity beyond intermittent acknowledgements from the chair. He emphasized the importance of meaningful dialogue at community meetings rather than moving on post-comments without substantial engagement.

(5:30) Barbara Stebbins addressed Item 9, "Authorizing CEO to Negotiate and Execute Leases and Consulting Services Agreement with Zevvy for EBCE Drive and Charge Research and Development Initiative" on the July 19, 2023 EBCE board agenda. This item would authorize an $85,000 investment for a Drive and Charge Research and Development Program as a segment of a broader $6 million plan aimed at promoting electric vehicle adoption, especially in areas with affordable multi-family housing. The initiative proposes leasing six types of electric vehicles to EBCE staff for two weeks, after which the participants would provide feedback via surveys. Stebbins expressed concerns over the program's potential effectiveness in achieving its primary goal. She proposed that instead of this approach, EBCE could channel the $85,000 towards Zevvy to offer free short-term leases to residents of affordable multi-family housing. This, she believes, would yield more relevant feedback and be a more impactful use of the funds.

The following is a summary of a written public comment that the clerk read in to the record:
(8:14) Richard Esteves from Quality Conservation Services responded to previous comments by Member Lisa Hu about the need for innovative collaborations to serve hard-to-reach populations in the EBCE community. Esteves proposed a collaboration between EBCE, Tesla, Swell Energy, and Quality Conservation to provide free whole-house battery storage systems to

Medical Baseline families residing in high fire-threat zones or those frequently affected by PSPS shut-offs. The installation would be funded by SGIP rebates, without EBCE incurring any cost. The estimated value of these systems is about $36,400 each. Given potential concerns over the magnitude of this offering, Esteves suggested piloting the program in one or two communities, such as Oakland which has 789 Medical Baseline customers. He highlighted the comparative advantage of their system over EBCE's existing medical baseline battery program, emphasizing its greater capacity and alignment with EBCE's energy priorities. He requested the CAC to consider this collaboration proposal and for the staff to assess and report on the offer during a subsequent CAC meeting.

C3. Approval of Minutes from June 20, 2023

(11:40) Member Lutz observed that in Item C5, “EBCE FY 2023-24 Budget” in the June 20, 2023 CAC minutes “on-time bill credit” should be changed to “one-time bill credit”.

Member Landry motioned to approve the minutes, pending Member Lutz’s requested correction. Member Lutz seconded the motion which passed 7/0/4
Excused: Members Hu, Liu, Talreja and Souza

C4. CAC Chair Report
Brand Identity Update:
Discussion about ongoing development of Ava Community Energy’s visual identity, including logo feedback, and planning for design finalization in September and an October soft launch.

CAC Chair Eldred provided updates from the June 21, 2023 Board meeting:

- The Board approved renaming the agency to Ava Community Energy.
- Community Advisory Committee seats were extended for six months.
- The Emissions Overview presentation was postponed again due to new data becoming available. The CAC chair expressed concern that this delays the Board hearing about EBCE's emissions.
- The Board approved the fiscal year 2023-24 budget, substituting the CAC's recommendation to hold one-time bill credit funds in an unspecified pool rather than allocating 50% to renewable energy. The CAC chair raised equity concerns about the credit structure.
- Annie Henderson gave an update that the Ava Community Energy branding process is underway to create a new logo and visual identity assets. These will come to the Board in September.

- Alex DiGordio announced that the City of Lathrop recently voted to seek EBCE membership, which requires further analysis and Board approval in the fall.
- Vice Chair Hernandez summarized some upcoming Board agenda items, including the CEO's contract extension and Treasury Report.
- The CAC Chair highlighted an item authorizing an electric vehicle research initiative that the CAC will not be discussing.
- There was discussion about logo design options and potential acronym issues with the rebranding to Ava.

C5. EBCE FY 2023-24 Budget (CAC Action Item)
Adopt a resolution approving the FY23-24 budget

(58:25) Member Pacheco inquired if the anticipated savings of two to three million dollars per year for the initial term was for the full 30-year duration or for a shorter term. He specifically referred to a bond period of five to ten years.

(59:24) Member Swaminathan asked Howard Chang about the volumes involved in each tranche as a percentage of the entire supply requirements.

Member Swaminathan further inquired about the point at which they would be considered sufficient in terms of load percentages, querying whether it might be 20%, 30%, or 40%.

(1:03:07) Member Lutz initiated the discussion by seeking clarification on whether the mechanism in question allows EBCE to borrow money at a more favorable rate than typically available.

Member Lutz then inquired if EBCE currently owns any generation sites, to which Howard Chang responded in the negative. When asked about future plans to own generation sites, Chang explained that historically it has not been a common practice for entities to own renewable assets due to efficiency reasons.

Finally, **Member Lutz** proposed a concept about the feasibility of directing bond investments back into the EBCE territory so that the interest payments benefit EBCE members. Howard Chang expressed that, in theory, it's an interesting idea. However, in practice, they work with large institutional bond investors, like Vanguard, and he wasn't aware of any such investors being based in Alameda County or San Joaquin County. **Member Lutz** clarified that he wasn't suggesting its immediate implementation but wanted to raise awareness for future consideration.

(1:08:34) Member Hernandez stressed the importance of local infrastructure investment by EBCE. Using the example of a client limited by current infrastructure, he highlighted the need for the EBCE to collaborate with the state to enhance local energy infrastructure. This would ensure resiliency, bring direct benefits to residents, and utilize the funds recently allocated by the governor for clean energy.

(1:13:04) Member Lutz motioned to approve the motion with the addition of asking the Board to direct staff to consider ways to benefit investors within EBCE territory. Member Pacheco seconded the motion.
The motion passed unanimously with all members present:
Yes: 7
No: 0
Excused: 4

C6. Amendment to Non-standard Rate Policy (CAC Action Item)
Revise policy to expand eligibility to beneficial electrification projects on municipal buildings

(1:21:52) Member Lutz inquired about EBCE's policy regarding matching energy rates from other companies. Alex DiGordio confirmed that EBCE could match rates within the stipulated policy guidelines, ensuring no losses and maintaining consistency with their renewable energy commitments. Member Lutz further questioned if EBCE intended to match rates for natural gas energy purchases from municipal entities. Alex DiGordio clarified that the intention is not to match natural gas rates but to incentivize municipalities, using the City of Piedmont's new pool as an example, to adopt costlier but environmentally friendly alternatives. Chair Eldred summarized that the approach allows EBCE to negotiate rates based on actual costs rather than relying on PG&E rates. Alex DiGordio agreed and emphasized that negotiations would remain within policy guidelines.

Public comment:
(1:25:30) Jessica Tovar asked how this policy would affect household rate payers. Alex DiGordio explained that the policy aims to retain large municipal, commercial, or industrial loads, which in turn supports EBCE's competitive advantages. By maintaining these advantages, EBCE can offer discounted rates to household rate payers.

(1:28:49) Member Lutz spoke in support of calculating EBCE rates independently of PG&E rates and stated that that EBCE rates should be calculated in a similar manner across the board.

<u>Member Pacheco motioned to approve the staff recommendation. Member Landry seconded the motion, which passed unanimously with all members present:</u>

<u>Yes: 7</u>
<u>No: 0</u>
<u>Excused: 4</u>

C7. Coordinating EBCE Local Development Actions: City Staff Perspectives (CAC Informational Item)
CAC Member Lutz presented findings from discussions he held with city sustainability staff from most EBCE member communities.

(1:46:30) Chair Eldred stated that she hoped that, as Member Lutz reaches out to other cities, that he encourages facilitation between city sustainability staff and their respective Board and CAC members.

Public Comment:
(1:47:34) Audrey Ichinose from East Bay Clean Power Alliance expressed her appreciation to Jim for his efforts to bridge understanding between municipalities and EBCE staff. She suggested that EBCE staff could expand the scope of board retreats to include more than just board members, citing the value of recent retreats on Analytics and Public Policy. These retreats allowed the public to gain deeper insights into EBCE's operational processes. Audrey Ichinose emphasized the benefits of broader engagement and commended Member Lutz for his proactive approach, noting the evident goodwill from all involved parties.

(1:49:47) Jessica Tovar highlighted that many cities have committed to renewable energy initiatives with the promise of more local investment and stressed the need for EBCE and cities to work in conjunction with communities to understand their desires for development and investment. Specifically, she noted a preference for focusing on building decarbonization over vehicle electrification, arguing that not everyone has access to electric vehicles. As a representative of Local Clean Energy Alliance, Tovar emphasized the importance of prioritizing community interests and ensuring that sustainability departments best represent their cities.

(1:52:30) Member Landry inquired about what kind of municipal program designs were being referenced when discussing the cities' desire for more collaboration and lead time. Member Lutz responded by using the example of EBCE's electric vehicle charging program. He explained that while EBCE had certain parameters in mind for placing chargers in large city lots, not all cities had spaces that could accommodate this. Thus, while the program design might work for some cities, it wouldn't be suitable for others. Member Lutz emphasized the importance of early collaboration and seeking input from cities during the program design phase to ensure the initiatives cater to each city's unique needs.

(1:54:29) Member Landry expressed her support for 100 percent renewable energy, referencing frequent comments made by Tom Kelly on the topic. She questioned if, given the previously approved policy on non-standard pricing rates for municipalities, EBCE staff could foster increased collaboration with cities, particularly in relation to their climate action plans and understanding their specific needs and program objectives.

(1:56:13) Member Pacheco shared his long-standing advocacy for the CAC and how he initially championed the initiative due to cities partnering for local innovations and renewable energy programs. He noted the challenge faced in getting the Community Choice Aggregation (CCA) included in Hayward's financial plan. He observed that many city councils view joining EBCE as a significant carbon reduction step, often treating it as a completed task without further coordination or innovation. Member Pacheco expressed interest in the detailed feedback from state building managers and appreciated the monthly meetings held by Alex DiGordio. He emphasized the potential for greater collaboration between EBCE staff, sustainability managers, and city councils to foster more innovation and a cohesive dialogue.

(1:58:26) Member Swaminathan requested that, once Member Lutz's findings are finalized, that EBCE staff review them and share their perspective. Additionally, he asked for a presentation detailing the various ways in which EBCE staff currently engage with city staff and their future plans for such engagements, covering all the different forums and avenues of their collaborations.

(2:00:04) Vice-Chair Hernandez emphasized the importance of collaboration in designing and building programs that effectively serve entities partnering with EBCE. He underscored the necessity of involving community organizations that promote clean jobs and local workers in these processes, ensuring that such programs result in quality job opportunities. By referencing infrastructure as an example, Vice-Chair Hernandez highlighted the need for a strategic roadmap detailing local development plans for the next 5-10 years. He compared the planning process to home building, stating that without initial collaboration, the project could face numerous inefficiencies and changes. Vice-Chair Hernandez concluded by emphasizing EBCE’s mission: to provide a more sustainable, inclusive, and affordable energy alternative to PG&E.

(2:02:12) Chair Eldred expressed enthusiasm over the evident eagerness of participating cities to align their budget cycles to better enroll in EBCE's programs and actively coordinate to fully utilize what the agency offers. She commended the staff for their impressive work, particularly praising JP Ross's contributions to the Local Development Business Plan. Chair Eldred was pleased to hear positive feedback about staff collaborations with city and county representatives. Chair Eldred acknowledged Member Lutz's initiative in this effort and stressed the value of such proactive involvement by CAC members. The Chair emphasized her desire to strengthen the engagement between CAC members and their respective jurisdictions, citing her personal involvement in Oakland's climate action planning as an example of productive collaboration.

C8. CAC Member and Staff Announcements including requests to place items on future CAC agendas

- **(2:05:44) Chair Eldred** recommended the creation of CAC Awards to recognize community members who are advocating in the green, clean and affordable energy space. Awards would be similar to former EBCE Chair Scott Haggarty's Chair Awards. Chair Eldred requested that Members recommend potential nominations to her.

- **(2:07:16) Vice-Chair Hernandez** requested to understand how EBCE might collaborate with the state to enhance the energy grid, using the development of local battery energy storage systems as an example. He expressed interest in understanding how EBCE can utilize its resources to invest in infrastructure and inquired about other potential initiatives EBCE might undertake.

- **(2:08:34) Member Landry** requested that Richard Esteves' July 17, 2023 public comment letter be forwarded to the board for follow-up, in particular the offer from Quality Conservation Services to set up a pilot to provide free whole-house battery storage systems to EBCE's Medical Baseline families.

C9. Adjournment to Monday, September 18, 2023 at 6:00 pm

CAC Item C4B
Staff Report

TO: East Bay Community Energy Community Advisory Committee

FROM: Cait Cady, Public Engagement Coordinator

SUBJECT: **EBCE Municipal Staff Coordination**

DATE: September 18, 2023

Recommendation

Receive an update on EBCE's ongoing engagement efforts with municipal staff partners.

Background and Discussion

A report was presented at the July Community Advisory Committee (CAC) meeting, in which Member Jim Lutz documented conversations with municipal sustainability staff from EBCE's member jurisdictions and summarized key findings about EBCE's current municipal engagement efforts. In response to this report, and subsequent interest from Members of the CAC on this topic, EBCE staff would like to share more information about the agency's ongoing efforts to engage with the staff of our member jurisdictions. EBCE staff were pleased to hear that municipal staff appreciate their jurisdiction's partnership with EBCE and we are always interested in hearing suggestions for how we can improve our public engagement efforts.

Summary of EBCE's Engagement with Municipal Staff Partners
EBCE sees municipal staff as key partners and stakeholders. As such, we strive for frequent and consistent collaboration.

A central component of our engagement strategy are the monthly meetings with municipal partners. These 'MuniPals' meetings are hosted by EBCE's Public Engagement team and designed to keep our muni partners up to date on all things

EBCE and provide a forum for feedback/questions. The meetings are often attended by members of the EBCE team across various departments, who share their expertise and project updates. Our MuniPals meetings regularly cover topics such as local development/programs, legislative tracking, customer care/billing updates, annual budget overviews, marketing efforts, and many more. Every month, EBCE staff coordinate internally to select topics we see as most pressing to share with municipal partners that month.

Additionally, between MuniPals meetings EBCE staff will regularly send out important updates to the group and monthly marketing toolkits to supply member jurisdictions with EBCE content for their own communications efforts.

In the report, a frequent topic was EBCE's engagement with municipal staff on local programs, with a recommendation that EBCE should be doing more to engage muni partners in program design. First, to highlight some of the engagement our team currently does, over the past year, local programs staff have joined 8 of the past 12 MuniPals meetings and provided lengthy updates on programs in all stages of development. For many of these programs, this initial outreach was a jumping off point for future coordination, numerous ad hoc conversations with interested city staff, and opportunities to solicit feedback on implementation.

Given EBCE's frequent engagement with city staff, we are aware that some staff partners would prefer a more involved role in program design. EBCE staff appreciate both the enthusiasm and critical expertise municipal staff partners can and do bring to these conversations. Our Local Programs team works diligently to collaborate with key stakeholders, like muni staff, for many programs, particularly regarding implementation planning. In terms of input on the overall direction of EBCE's programmatic efforts, the Board of Directors is responsible for deciding what programs the agency will pursue, but we encourage coordination between municipal staff and their respective Board Member.

Some programs more than others are very well positioned for significant muni staff input, like those that are designed for municipalities specifically. The Critical Municipal Facilities Resilience program is a great example of this type of program, and municipal staff engagement has been at the center of implementation. The program was designed to address key barriers that our municipal staff colleagues identified for implementing resilience projects in their cities and EBCE has been in constant coordination with our municipal colleagues throughout several phases of the program.

Lastly, when EBCE starts developing new programs, staff design them to serve communities all across the service area. However, there may be times when a program is available to some cities but not all due to a multi-phased implementation approach. For example, public EV charger deployment and the Critical Municipal Facilities Resilience program utilized this approach and were not available to all cities at the time of their initial rollout.

Comparison to Other CCAs/Utilities
EBCE staff wanted to learn more about how other regional agencies, especially neighboring CCAs, engage with municipal staff from the communities that they serve. After soliciting feedback from neighboring CCAs about their engagement practices, it appears that EBCE's current engagement strategy already meets or goes above and beyond many best practices in the industry. For example, many comparable agencies do not host regular meetings with municipal staff.

Conclusion
EBCE is grateful for the high levels of engagement from our municipal staff colleagues, and we look forward to continuing this close partnership.

Fiscal Impact

This update has no fiscal impact.

Docket No.: R.23-01-007

Exhibit No.:

Date: June 9, 2023

Witnesses: Brian Dickman

OPENING TESTIMONY OF BRIAN DICKMAN
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

RULEMAKING IMPLEMENTING SENATE BILL 846 CONCERNING POTENTIAL EXTENSION OF DIABLO CANYON POWER PLAN OPERATIONS

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ATTACHMENTS

I. INTRODUCTION AND SUMMARY OF TESTIMONY

The California Community Choice Association (**CalCCA**) presents this opening testimony in the *Rulemaking Implementing Senate Bill 846* (**SB 846**) *Concerning Potential Extension of Diablo Canyon Power Plant Operations*[1] (**DCPP OIR**). This testimony has been prepared on behalf of CalCCA by Brian Dickman, Partner, NewGen Strategies and Solutions, LLC. Mr. Dickman's qualifications are set forth in Attachment A.

CalCCA has a particular interest in the Diablo Canyon Power Plant (**DCPP**) extended operations and this DCPP OIR because SB 846 directs that certain costs of extended operations will be recovered from customers of all load-serving entities (**LSEs**) subject to the California Public Utilities Commission's (**Commission**) jurisdiction, including customers of community choice aggregators (**CCA**) that are members of CalCCA. This testimony presents CalCCA's proposals on certain issues falling within Phase 1: Track 2 as established in the April 6, 2023, Assigned Commissioner's Scoping Memo and Ruling[2] (**OIR Scoping Ruling**). Specifically, CalCCA's proposals address three scoping items, listed below:[3]

1. If the Commission directs and authorizes extended operations at DCPP, what are the new processes to authorize annual recovery of all reasonable DCPP extended operation costs and expenses on a forecast basis, including allocation of forecast costs among Commission-jurisdictional load-serving entities.

2. Whether additional cost recovery mechanisms, agreements, plans, and/or orders are needed prior to the current retirement dates for Diablo Canyon Units 1 and 2 (i.e., in 2024 and 2025, respectively).

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[1] Rulemaking (**R.**) 23-01-007, *Rulemaking Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations* (Jan. 12, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M501/K368/501368884.PDF.

[2] R.23-01-007, *Assigned Commissioner's Scoping Memo and Ruling* (Apr. 6, 2023) (**Scoping Ruling**), at 5-6: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M505/K462/505462882.PDF.

[3] CalCCA reserves the right to respond or comment on other matters within the scope of this proceeding at the appropriate time as included in the OIR Scoping Ruling or other scoping rulings during the course of the proceeding.

3. Whether and how the benefits of extended operations, including resource adequacy and greenhouse gas-free attributes, should be allocated among the LSEs and customers paying for extended operations.

As described further in my testimony, CalCCA recommends the following:

- The Commission should adopt the same process currently used for resources subject to the Cost Allocation Mechanism (**CAM**) to allocate DCPP's resource adequacy (**RA**) capacity to all LSEs contributing toward cost recovery. Capacity should be allocated based on each entity's proportional contribution to the group's combined 12-month coincident peak.

- The Commission should require DCPP's green-house gas (**GHG**)-Free attributes be made available to all LSEs contributing toward cost recovery through a voluntary allocation, similar to the current 'interim' approach approved for Pacific Gas and Electric Company's (**PG&E**) large hydroelectric and nuclear facilities.

- The Commission should require PG&E to file a stand-alone application seeking approval of the forecasted net costs of DCPP continued operations on an annual basis. PG&E should be required to present detailed projections of all DCPP costs and revenues in a format similar to the information provided in its general rate case (**GRC**) and Energy Resource Recovery Account (**ERRA**) proceedings.

- Net DCPP costs that are to be recovered from customers of all jurisdictional LSEs in the state should be allocated to investor-owned utility (**IOU**) service territories based on the contribution to the group's combined 12-month coincident peak.

- The Commission should require PG&E to track the net costs of DCPP extended operations in a new balancing account and recover those costs through a new non-bypassable charge (**NBC**) included in each IOU's delivery rates.

- In sum, the ratemaking process for DCPP costs would be:

    1. PG&E prepares an annual DCPP Forecast Application that is similar to but separate from the ERRA Forecast Application.

    2. A Commission decision in the DCPP Forecast Application sets the level of the revenue requirement to be collected through the DCPP-specific NBC in each IOU's service territory.

    3. That revenue requirement is translated to a $/kWh charge for eligible customers in an IOU's service territory in November and December via each IOU's consolidated rate change advice letter filing.

II. CUSTOMERS PAYING FOR EXTENDED OPERATIONS SHOULD RECEIVE THE BENEFITS OF DCPP'S RA AND GHG-FREE ATTRIBUTES

There are two ways for the Commission to ensure customers benefit from the value of a resource's attributes. *First*, the Commission might assign customers a credit against retail rates. *Second*, the Commission might allocate resource attributes among the LSEs serving those customers.

Currently, the Commission follows the first approach for DCPP. The costs to own and operate DCPP are recovered from bundled and departed load customers in PG&E's service territory through Power Charge Indifference Adjustment (**PCIA**) rates, which are structured to recognize the value of DCPP's generation-related attributes as a credit against retail rates. PG&E charges customers for DCPP's above-market costs, calculated as the cost of the resource less the market value of its energy and capacity. Generation output is sold into the CAISO market, and the market revenue is netted against DCPP costs. The value of DCPP RA that PG&E retains to meet a portion of its bundled customer RA requirement is reflected as a credit against DCPP costs and reduces PCIA rates for customers. Revenue received from sales of DCPP RA, if any, to third parties is also credited against DCPP costs.

Going forward, costs associated with extended operations at DCPP will not be recovered through the PCIA. Instead, SB 846 allows PG&E to charge customers a new NBC to recover all "reasonable costs and expenses necessary to operate [DCPP] beyond the current expiration dates,"[4] net of market revenue from DCPP operation. Under the cost recovery regime described in SB 846, customer rates will no longer reflect a credit

[4] Cal. Pub. Util. Code § 712.8(h)(1).

for the value of RA, nor will they reflect a credit to recognize the value of the GHG-free attribute of the generation.

Consequently, the Commission would need to follow the second method to ensure that customers that pay the cost of continued DCPP operation realize the value of continued operations.

A. Costs And Benefits of DCPP Extended Operations Should Be Aligned and Fairly Allocated to Customers

1. SB 846 Shifts The Financial Risk of Extending DCPP Operations to Customers, and They Should Benefit Accordingly

SB 846 alters the cost recovery framework for DCPP during extended operations and shifts the financial risk of extending operations to customers throughout California. Pursuant to SB 846, PG&E will assess several new charges to customers to compensate PG&E shareholders "in lieu of a rate-based return on investments and in acknowledgment of the greater risk of outages in an older plant."[5] Specifically, PG&E will collect $13.00/MWh for each MWh generated by DCPP, plus a fixed payment of $100 million ($50 million per unit) annually. Together, these fees collected in lieu of a rate-based return total approximately $320 million[6] per year, compared to $143 million in annual return on rate base proposed by PG&E in its 2023 GRC. SB 846 entitles PG&E to recover from customers the cost of replacement power during unplanned outage periods, *even if the unplanned outage is the result of a failure by PG&E to meet the reasonable manager standard*.[7] In fact, PG&E is allowed to charge all customers up front to fund a $300 million liquidated damages balancing account that can be used to cover the cost of

[5] Cal. Pub. Util. Code § 712.8(f)(5) and § 712.8(f)(6).
[6] Volumetric payments estimated based on actual generation output during 2021.
[7] Cal. Pub. Util. Code § 712.8(i)(1).

replacement power during these imprudent outages. It is not reasonable for customers to bear all of these costs, including more than doubling the payments to PG&E shareholders, without realizing the corresponding benefits of the plant's extended operation.

2. The Commission Should Follow The CAM Model To Allocate The Costs and Benefits of DCPP Extended Operations

SB 846 extended the life of the DCPP plant for the benefit of all California's electric customers while designating a single IOU, PG&E, as the operator. Public Resources Code Section 25548.7 states, "Continued operation of the Diablo Canyon powerplant as provided in this chapter is in all respects for the welfare and the benefit of the people of the state…" Based on this rationale, SB 846 also alters the cost recovery framework for DCPP during extended operations. SB 846 entitles PG&E to recover the reasonable and necessary costs to operate DCPP beyond the current expiration dates, net of market revenue from DCPP operation. With limited exceptions, SB 846 specifies that DCPP extended operations costs are to be recovered from customers of all jurisdictional LSEs in California.

The rationale and framework for extending DCPP operations described in SB 846 is similar to the CAM concept originally established by the Commission in Decision (**D.**) 06-07-029. The Commission adopted the CAM as a mechanism to streamline procurement of critical new resources for the benefit of multiple customer groups (e.g., bundled and unbundled customers). In D.06-07-029 the Commission stated, "[We] are adopting a cost-allocation mechanism… that allows the advantages and costs of new generation to be shared by all benefiting customers in an IOU's service territory. We designate the IOUs to procure this new generation. The LSEs in the IOU's service territory will be allocated rights to the capacity that can be applied toward each LSE's RA requirements. The LSE's customers receiving the benefit of this additional capacity pay only for the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract."[8]

As directed by the Commission, IOUs procure CAM resources for the benefit of all customers in their respective service territories. CAM resource costs, net of revenues from selling energy and ancillary services into the California Independent System Operator (**CAISO**) market, are then recovered from all customers in each IOU's service territory through a volumetric NBC. PG&E's CAM NBC is known as the New System Generation Charge (**NSGC**).

Recognizing the similarities between CAM and DCPP extended operations, a fundamental principle that should be followed here is that the allocation of costs and benefits should be aligned and fairly distributed to customers. When establishing the CAM, the Commission determined, "[a]ll RA counting benefits and net costs are spread to the LSEs whose customers are allocated costs based on share of 12-month coincident peak, adjusted on a monthly basis to facilitate load migration. The contract costs paid and RA benefits received by [departed load] and bundled customers should be based on a share basis equal to the credit share received."[9]

The Commission should allocate the costs and benefits of DCPP extended operations the same way it allocates the costs and benefits of CAM resources. Specifically, net costs that PG&E will recover from customers of all jurisdictional LSEs in the state, per SB 846, should be allocated to IOU service territories based on the contribution to the group's combined 12-month coincident peak.[10] As I describe later in

[8] D.06-07-029 at 7.

[9] *Id*. at 31.

[10] The 12-month coincident peak allocation should be consistent with the RA attribute allocation prepared by Energy Division to match costs and benefits.

my testimony, each IOU would recover the allocated DCPP costs from all customers in its service territory through a new NBC included in delivery rates.

Each Commission-jurisdictional LSE should also receive a proportional share of DCPP's RA attributes, based on a share of the 12-month coincident peak. At a high level, following the CAM procedures already in place for the Commission's RA compliance program, Energy Division should include an allocation of DCPP RA capacity in the RA template for each LSE, reducing the System RA requirement for each LSE by its share of DCPP capacity for compliance periods during extended operations. Below, I describe in more detail how the Commission should allocate DCPP RA to LSEs.

B. DCPP RA Capacity Should Be Allocated to LSEs

1. Allocating DCPP RA To LSEs Will Avoid Artificially Understating Resources Available in A Constrained Market

California LSEs face a constrained RA market, despite the fact that DCPP remains in operation. Several different analyses have now concluded that, unless recent weather patterns shift back to "normal," to avoid significant capacity shortages until unprecedented amounts of new resources can be brought online, DCPP should continue to operate. As LSEs seek to procure sufficient resources to meet their obligations under the Commission's Resource Adequacy program they are *already* faced with year-over-year price increases, price spikes in high demand summer months, and a lack of capacity available in the market. Ignoring DCPP in the RA market, especially when it is still operating and providing system capacity, will only exacerbate the market constraints and artificially increase rates.

The California Energy Commission (**CEC**) staff report on Diablo Canyon Power Plant Extension (**CEC Report**) published in March 2023 recommends the CEC determine that it is prudent for the state to pursue extension of DCPP due to the risk that sufficient resources may not be built in time to reach procurement targets ordered by the Commission and to address potential grid demands in extreme heat events.[11] The CEC Report relies on a deterministic resource stack analysis to evaluate capacity needs through 2032 assuming DCPP units are retired. The analysis indicates that under planning, or 'normal,' circumstances the CAISO market should have sufficient capacity to meet demand. However, the report demonstrates that deviations from normal conditions, such as the heat waves experienced in California during 2020 and 2022, will put significant strain on the available capacity and result in resource shortages during critical summer months.

The CEC also recognizes that its analysis relies on aggressive assumptions, including the "ability to build new clean energy resources at a pace not seen before and in the face of supply chain, interconnection, and permitting delays."[12] In fact, when the CEC considered resource delays and summer temperatures equivalent to those experienced in 2022, the stack analysis demonstrates anticipated capacity shortfalls exceeding 2,000 MW through 2029.

The relevance of this conclusion is underscored by the Joint Agency Reliability Planning Assessment (**Joint Agency Report**) published by the CEC and the Commission in February 2023. The Joint Agency Report details that climate driven events had a significant impact on CAISO system reliability *in each of the last three years*:

> Climate change is causing substantial variability in weather patterns and an increase in climate-driven natural disasters, which is resulting in more challenges to maintaining grid reliability. In 2020, a west-wide heat event resulted in rotating outages August 14 and 15. In 2021, dry conditions resulted in a wildfire in Oregon that impacted transmission lines that California depends on for

[11] CEC Report at. ii.
[12] *Id*. at 25.

> reliability, resulting in a loss of 3,000 megawatts (MW) of imports to the California Independent System Operator (California ISO) territory and 4,000 MW of overall import capacity to the state. In 2022, California experienced record high temperatures between August 31 and September 9. On September 6, 2022, the California ISO recorded a new record peak load at 52,061 MW, nearly 2,000 MW higher than the previous record, despite significant efforts to reduce load during this peak period.[13]

As part of its reliability assessment, the Joint Agency Report concluded that if DCPP is retired by 2025, capacity shortfalls of 500 MW to 3,800 MW are expected between 2023 and 2027 unless the heat events that occurred in 2020 and 2022 are aberrations and not part of the 'new normal' Californians face.[14]

The CEC Report also acknowledges the shortcomings of a deterministic stack analysis approach, stating, "It is difficult to articulate the probability of the outcomes contained in the results from a deterministic stack approach. Thus, the actual probability of the outage risks associated with different supply and demand balances are uncertain, especially when looking far into the future."[15] Notably, the CAISO conducted a probabilistic production cost modeling analysis to support the Commission IRP process, inform summer preparedness activities, and support the CEC's evaluation of the prudence of extending DCPP operation. The CAISO analysis found capacity shortages between approximately 750 MW and 1,285 MW are expected in 2025 and 2026, even after considering new resource additions identified in the IRP or as ordered by Commission procurement decisions.[16]

CalCCA witnesses Eric Little and Andrew Mills sponsor testimony in this proceeding to present an analysis of the constrained RA market published by CalCCA in

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13 Joint Agency Reliability Planning Assessment at 7 (Feb. 2023).

14 *Id.* at 50.

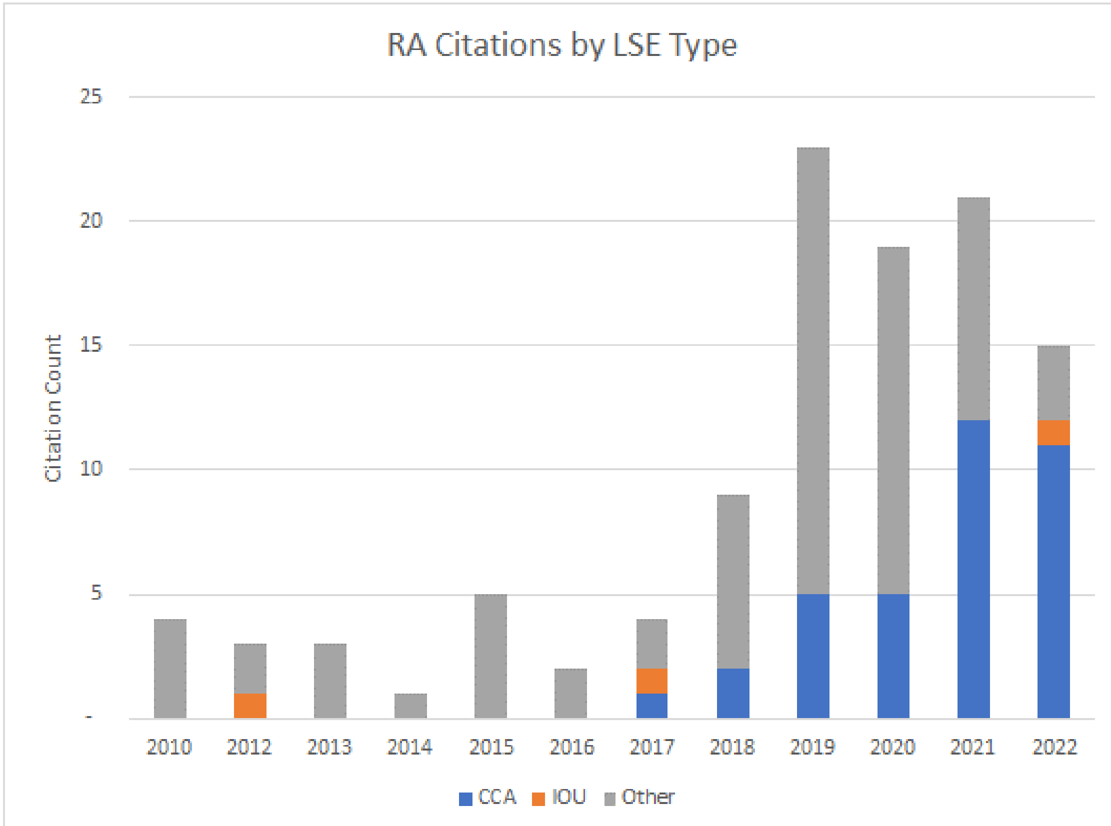
15 CEC Report at 16.

16 February 2, 2023 Letter to CEC Vice Chair, available at http://www.caiso.com/Documents/Jan2-2023-Letter-CaliforniaEnergyCommissionViceChair-CAISOReliabilityModeling.pdf.

March 2023 (**CalCCA Stack Analysis**), updated to include recent information regarding the status of the RA market. The CalCCA Stack Analysis concurs with the CEC's analysis, finding that certain conditions similar to those considered in the CEC analysis are contributing to RA shortfalls including extreme weather conditions, declining hydro resource availability due to drought, delays bringing new resources online, increasing capacity needs across the Western region, and restrictive regulatory requirements. Based on its updated analysis, CalCCA anticipates a 433 MW shortage for 2023, growing to a 1,258 MW shortage in 2025.

All of these assessments point to the same conclusion: capacity is scarce, it will remain scarce, and DCPP provides needed System RA. One symptom of the constrained RA market is that many LSEs have been unable to meet their System RA requirements despite being willing to pay. The Enforcement Actions Spreadsheet updated by the Consumer Protection and Enforcement Division in February 2023 tracks RA citations issues to various entities from October 2009 through November 2022. As shown in Figure 1, there was a sharp increase in the number of citations in 2019, and elevated levels continued through 2022.

Figure 1



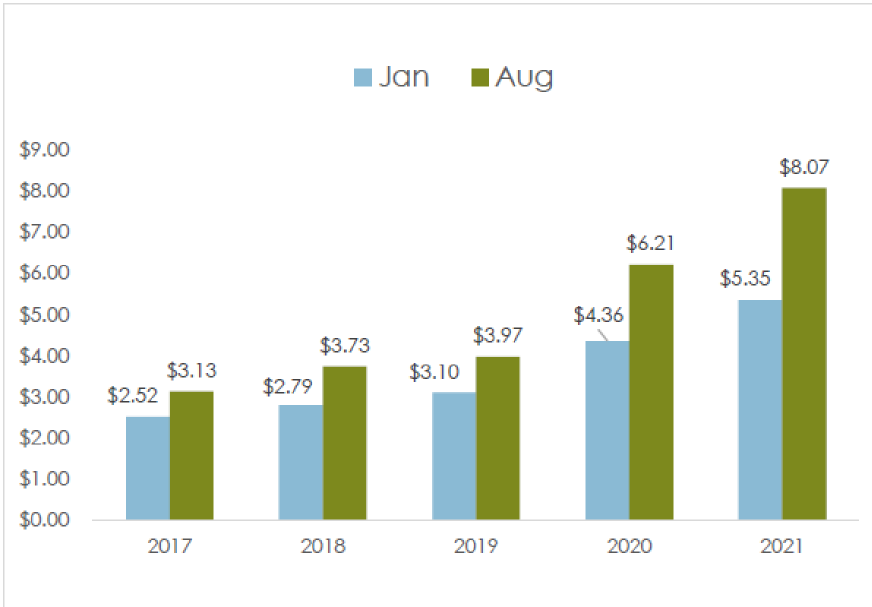
Another symptom of the constrained market is the steadily increasing price of System RA. Figure 2 below reproduces Figure 4 from the 2021 Resource Adequacy Report,[17] showing the rise in RA prices from 2017 to 2021.

[17] *2021 Resource Adequacy Report*: https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report_040523.pdf.

Figure 2

2021 Resource Adequacy Report

Figure 4: Weighted Average Price of System RA ($/kW-month), January and August 2017- 2021



Source: 2017-2021 price data submitted by LSEs.

As the figure shows, Energy Division's 2021 Resource Adequacy Report illustrates that the average price of System RA transactions executed for August 2021 was 158% higher than for August 2017.[18] The RA market price benchmarks calculated by Energy Division in September 2022 report that System RA prices in 2022 averaged $8.11/kW-month over the entire year, and the forecast for average System RA prices in 2023 is $7.39/kW-month.

Energy Division's data also shows that variation in RA prices during 2021 was significantly greater during high-demand summer months relative to other periods; prices for 15 percent of transactions exceeded $14/kW-month during July – September 2021.[19]

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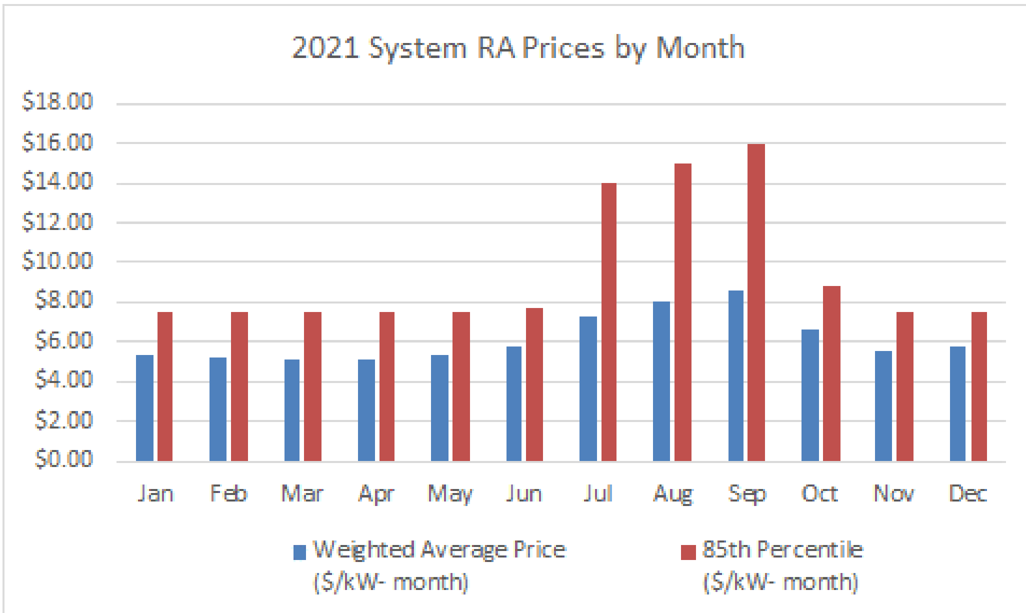
[18] *Id.* at 28-29.
[19] *Id.* at 27-28.

The CalCCA Stack Analysis concurs, finding “Resources that garnered $3.63 kilowatt (kW)-month in 2019 rose to prices as high as the mid-$40 kW-month for summer 2023 and are increasingly unavailable at any price.”[20] Figure 3 below presents Energy Division’s monthly price data for 2021 in graph form.

Figure 3



Price spikes such as these in the short-term RA market simply create a windfall for existing generation owners at the expense of retail consumers. There is no incremental reliability benefit to the system from these increased costs.

Withholding DCPP’s 2,280 MW of capacity from the RA market would worsen the market constraints causing such spikes. Further squeezing the RA market by ignoring DCPP will increase costs for customers by over $200 million[21] annually as they are required to procure RA rather than count the DCPP capacity they pay for during extended operations. There will be no incremental reliability benefit accompanying this dramatic rate increase.

20 CalCCA Stack Analysis at 2. Internal citation omitted.
21 2,280 MW * $7.39/kW-month * 1,000 * 12 = $202.2 million.

2. Allocating DCPP's Attributes Will Not Impact The State's Long-Term Planning Goals

Regardless of the cause of the scarcity in the RA market, and the resulting high prices, California will need more resources to contribute to meeting the Commission's RA requirements until new zero-carbon reliability resources can be built. Recognizing this need, SB 846 describes the purpose of extending DCPP operation: "Preserving the option of continued operations of the Diablo Canyon powerplant for an additional five years beyond 2025 may be necessary to improve statewide energy system reliability and to reduce the emissions of greenhouse gases while additional renewable energy and zero-carbon resources come online, *until those new renewable energy and zero-carbon resources are adequate to meet demand*."[22]

In Reply Comments on the Order Instituting Rulemaking to establish this proceeding, PG&E argued, "RA allocation to reduce RA compliance procurement activity is in conflict with Legislative direction that the state act with urgency to bring clean replacement energy to support reliability and achieve California's landmark climate goals."[23] This position ignores the difference between the Integrated Resource Planning (**IRP**) process and the Commissions procurement focused decisions, which drive the construction of new resources, and RA compliance, which drives near-term LSE procurement to optimize the use of already-existing resources. California's IRP process for Commission-jurisdictional LSEs comprises two parts: 1) identifying an optimal portfolio for meeting state policy objectives, and 2) aggregating the LSEs' collective efforts for planned

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22 PRC § 25548(b). Emphasis added.

23 R.23-01-007, *Reply Comments of Pacific Gas And Electric Company (U 39 E) on Administrative Law Judge's Ruling Requesting Comments on Phase 1: Track 1 Issues* (May 31, 2023) (**PG&E Reply Comments**), at 8: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M510/K286/510286991.PDF.

and contracted resources to compare to the optimal system. The Commission IRP process requires jurisdictional LSEs to submit plans every two years to ensure they can meet GHG reduction targets while maintaining system reliability.[24] In the IRP planning track, the Commission adopts a preferred system plan identifying the optimal portfolio spanning over a ten-year forecast period, and then sets requirements for LSEs to plan toward that future. "To the extent that the CPUC orders procurement in the IRP proceeding, it is generally to meet a reliability or GHG reduction need identified in the planning track."[25]

The purpose of the Commission's RA program is to ensure capacity resources are contracted for and available to meet California demand in the short term. The Commission describes that the RA program "guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO when and where needed."[26] The RA program has two types of filings: annual and monthly. On an annual basis, LSEs are required to demonstrate that they have procured 90% of their System RA obligation for the five summer months of the coming compliance year. On a monthly basis, LSEs must demonstrate they have procured 100% of their monthly System RA obligation. LSEs can demonstrate compliance with their RA obligations either through long-term procurement (i.e., pursuant to the IRP and Commission procurement decisions) or through purchases of RA capacity from third parties in the bilateral market.

PG&E also argued in its Reply Comments that allocated RA capacity from DCPP to LSEs for RA compliance purposes "would in effect provide a procurement reprieve to

[24] Joint Agency Report at 25.
[25] *Id.* at 26.
[26] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage, accessed May 23, 2023.

LSEs, thus, countering the incentive for LSEs to engage in incremental procurement to improve reliability of the state's electrical system…[T]he Commission is currently considering extended operation through 2030 and, if LSEs assume RA and GHG-free energy from DCPP through 2030, that could impact whether they enter into contracts today for delivery in the late 2020s."[27]

This is not true. The Commission's IRP process and ensuing procurement decisions will continue to dictate the pace of long-term resource procurement even if DCPP RA counts toward jurisdictional LSEs' RA compliance obligations in the near term. SB 846 prohibits LSEs from including DCPP energy, capacity, or GHG-free attributes in their resource planning and requires the state to continue to act with urgency to bring clean replacement energy online.[28] As discussed earlier, however, long-term resource planning differs from short-term RA compliance procurement. Furthermore, LSEs are already acting to bring new capacity online from 2021 through 2026 pursuant to procurement requirements in D.19-11-016 and D.21-06-035, although the Commission recognized in D.23-02-040 challenges related to procuring long-lead time resources. The Joint Agency Report confirms, "Between 2020 and late 2022, the CPUC's IRP procurement orders and prior LSE procurement resulted in over 11,000 MW of new nameplate energy resources, equivalent to over 6,000 MW of new Net Qualifying Capacity (NQC) that can count toward RA capacity obligations."[29]

Even after accounting for resource additions ordered or planned through the IRP process, the Joint Agency Report found that, under extreme weather conditions, capacity

[27] PG&E Reply Comments at 8-9.
[28] PRC § 25548(c).
[29] Joint Agency Report at 29.

shortfalls are expected to continue throughout DCPP extended operations. Factoring in possible delays in planned procurement due to supply chain challenges only increases the expected shortfalls. In short, the risk of insufficient or delayed resource procurement *drives* the need to extend DCPP operations; extension of operations is not the *cause* of delayed procurement.

DCPP RA should be allocated among all LSEs whose customers will pay for the cost of extended operations to avoid artificially understating available resources in an already constrained RA market. The IRP and Commission procurement directives will ensure new resources will be built over the long term. The Commission designed the RA program to ensure resources are under contract and available to meet peak demand in the short term. Removing DCPP from the pool of resources available to count toward System RA requirements will artificially constrict the market, despite DCPP's continued operation.

C. The Commission Should Direct PG&E To Continue Offering Voluntary Allocations of DCPP's GHG-Free Attributes To LSEs

In R.17-06-026, the Commission has been evaluating whether it should incorporate a credit for GHG-Free attributes into the PCIA to reflect the premium value of GHG-Free energy as an offset to resource costs. Analysis of historical market transaction data led Energy Division to conclude in September 2022 that "there is currently a premium for GHG-Free resources" in California and to recommend the value be recognized in the PCIA.[30] GHG-Free energy has value to LSEs because it impacts

[30] R.17-06-026, *Administrative Law Judge's Ruling Requesting Comments on GHG-Free Resources Staff Proposal and Other Issues* (Sept. 12, 2022), Attachment A, "GHG Free Data Analysis and Staff Proposal" (**September 12 Staff Proposal**), at 5: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=496874129.

LSEs' carbon intensity for the purpose of their Power Content Label.[31] Receiving GHG-Free energy also impacts LSEs' marketing efforts. On May 4, 2023, the Commission issued a proposed decision in R.17-06-026 (**PCIA OIR Proposed Decision**) finding that there was sufficient data to support a "heightened value for GHG-Free resources, which can be attributed to [Power Content Label] value or meeting an individual LSEs' GHG reduction goals more broadly."[32]

The Commission should require PG&E to offer allocations of DCPP's GHG-Free attributes to LSEs whose customers will pay for extended operations. Doing so simply requires the Commission to continue the *status quo*, with a few modifications. Resolution E-5111 approved PG&E's current 'interim' allocation process which allocates GHG-Free attributes from resources in PG&E's PCIA portfolio.[33] PG&E offers LSEs within its service territory an allocated amount of GHG-Free energy generated by specified facilities corresponding to each LSE's "Allocation Ratio."[34] Once a year PG&E offers each LSE its Allocation Ratio which, after execution of a Sales Agreement, corresponds to an allocated quantity of GHG-Free energy sold to the LSE during the delivery year. Under this framework, LSEs that accept the allocations may report the corresponding

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31 Under the CEC's Power Source Disclosure program, LSEs must disclose to their customers the mix of sources used to provide electricity service during the previous calendar year, and the greenhouse gas emissions intensity of their portfolio. The annual disclosure is made on an LSE's "Power Content Label."

32 R.17-06-026, Proposed *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access* (issued May 4, 2023), at 17: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K069/508069560.PDF.

33 Allocation of PG&E's GHG-Free resource was first approved in Resolution E-5046, which adopted Appendix P to PG&E's 2014 Bundled Procurement Plan specifying the terms under which GHG-Free attributes would be allocated. Resolution E-5111 approved several modifications to Appendix P based on experience with the allocation process to that point.

34 The Allocation Ratio is defined as the LSE's monthly load forecast used in PG&E's ERRA Forecast Application compared to the total forecasted load for customers responsible for the costs of the resources. Because allocation of DCPP GHG-Free attributes during extended operations would involve LSE outside of PG&E's service territory, the CEC's California Energy Demand forecast, as updated annually, could be used to determine the applicable Allocation Ratio.

GHG-Free energy on their annual Power Content Label under the CEC's Power Source Disclosure Program.

PG&E should continue to offer voluntary allocations of the GHG-free attributes associated with DCPP.[35] PG&E's existing allocation process needs only minor modifications to conform to DCPP's extended operations. PG&E should modify its Bundled Procurement Plan (**BPP**) Appendix P to accommodate an annual allocation and offer process for DCPP as a stand-alone specified resource. Under my proposal, PG&E would calculate DCPP GHG-Free generation separate from PG&E's other resources, and would expand eligibility to receive an allocation of DCPP generation to all California LSEs subject to the DCPP NBC, including PG&E and other IOUs. LSEs can confirm their acceptance of an allocation by executing a sales agreement with PG&E subject to the conditions in PG&E's BPP Appendix P. Unclaimed allocations, if any, would be unused for that delivery year and would not be reported on any individual LSE PCL or other communications.

Continuing voluntary allocations is a reasonable approach to ensuring that cost-responsible customers continue to have the option of receiving the benefits of DCPP's GHG-free energy.

[35] The PCIA OIR Proposed Decision adopts a GHG-Free allocation or Market Price Benchmark process for large hydroelectric resources, and allows, but does not require, the IOUs to continue to offer allocations of GHG-Free attributes from PCIA-eligible nuclear resources on a voluntary, annual basis. The PCIA OIR Proposed Decision ties this framework to the PCIA and eliminates it once the PCIA sunsets. It does not address the continuation of voluntary allocation under a non-PCIA rate mechanism.

III. PG&E SHOULD BE REQUIRED TO FILE A STAND-ALONE APPLICATION SEEKING APPROVAL OF THE FORECASTED NET COSTS OF DCPP CONTINUED OPERATION ON AN ANNUAL BASIS

A. A New Annual Application for The Recovery of The Forecasted Costs of DCPP Extended Operations Should Be Structured in The Same Manner As PG&E's Annual ERRA Forecast Proceeding

PG&E currently establishes the annual cost to operate DCPP through a combination of its GRCs, annual ERRA proceedings, and other filings to address specific issues such as employee retention and decommissioning costs.[36] PG&E recovers DCPP costs from bundled and departed load customers in its service territory through PCIA and Nuclear Decommissioning rates.[37] SB 846 directed the Commission to authorize PG&E to recover the net cost of DCPP extended operations through a new proceeding structured similarly to its annual ERRA Forecast proceeding.[38]

For the period of DCPP extended operations, PG&E should present for approval a single application with an annual forecast of all DCPP-related costs eligible for recovery from ratepayers (**DCPP Forecast Application**). As California Public Utilities Code Section 712.8(h)(1) suggests, the DCPP Forecast Application should follow a similar process as the ERRA Forecast proceeding, *i.e.*, an initial application presenting PG&E's forecast of net costs for the subsequent year, followed by a period of party review and opportunities to file testimony. PG&E should also be required to submit an update to forecasted costs, during the pendency of the annual forecast proceeding, to capture the most recent market conditions available prior to establishing the final net cost forecast. [39] The Commission should require

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36 PG&E Response to CalCCA Data Request 1.01.

37 PG&E Response to CalCCA Data Request 1.02.

38 Cal. Pub. Util. Code § 712.8(h)(l).

39 In PG&E's annual ERRA Forecast proceedings, PG&E files a "Fall Update" in October providing updated forecasted costs.

PG&E to prepare its annual DCPP Forecast Application based on the same forecast assumptions used to develop the ERRA Forecast for the corresponding period (including, for example, forecasted market revenues, fuel costs, generation output, and other variables), and procedural milestones in the DCPP Forecast Application should follow a timeline that runs in parallel with the ERRA Forecast proceeding.

Despite the similarity between the two filings, the DCPP Forecast Application should be a standalone application to facilitate participation from all affected stakeholders in the state without complicating PG&E's ERRA Forecast application process. That application is typically limited to a handful of parties seeking to address PG&E-specific issues and rarely includes the other IOUs as parties. Moreover, a substantial amount of work is done in that proceeding, including ratemaking and the implementation of policy directed by other cases. Examples of these issues in just the past few years include:

- The methodology to refund a CAM misallocation;[40]
- The methodology to return ERRA overcollections in an equitable manner;[41]
- The methodology to calculate the RA component of Green Tariff Shared Renewable rates;[42]
- Implementation of changes to the methodology used to calculate the PCIA from D.18-10-019 and D.19-10-001;[43]
- The inclusion of unapproved Catastrophic Event Memorandum Account and Wildfire Expense Memorandum Account costs in the PCIA revenue requirement;[44] and

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40 D.20-02-047 at 10.
41 *Id*. at 11-12.
42 D.20-12-038 at 28-29.
43 *See, e.g.,* D.18-10-019 at Ordering Paragraphs (**OPs**) 8 and 10; D.19-10-001 at OPs 2-4.
44 A.21-06-001, PG&E Prepared Testimony at 9-8:10-16 to 9-9:1-4 and Table 9-2.

- Addressing the accounting resulting from PG&E acting as a Central Procurement Entity (D.20-06-002), to meet 2021 summer reliability targets (D.21-02-028); or to meet the incremental procurement targets 2021-2023 (D.19-11-016) that impact the CAM balancing account, ModCAM balancing accounts and the Portfolio Allocation Balancing Account.

Creating a standalone proceeding for DCPP-related issues would avoid overwhelming the expedited ERRA Forecast proceeding with parties and issues that seek to only address DCPP-related issues. The significant non-DCPP-related policy and implementation issues are frequently addressed in PG&E's ERRA Forecast proceeding.

PG&E would no longer present DCPP-related costs in its ERRA Forecast or recover those costs through PCIA rates during the period of extended operations. Rather, PG&E would recover the Commission-approved DCPP net cost forecast through distinct NBCs included in the delivery rates for each IOU's service territory.

Each year as part of the DCPP Forecast Application the Commission would approve 1) the total forecasted DCPP net costs, and 2) the amount allocated to customers in each IOU's service territory. Each IOU would then be responsible for calculating the corresponding volumetric NBC charged to customers of all jurisdictional LSEs based on electricity consumption in their own service territory.[45] The IOUs would include their respective NBCs in delivery rates via each IOU's annual consolidated rate change advice letter process (*e.g.*, the Consolidated Rate Change in Southern California Edison's service territory and the Annual Electric True-UP (**AET**) in PG&E's service territory).[46]

In sum, the ratemaking process for DCPP costs would be:

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[45] Cal. Pub. Util. Code § 712.8(l)(1).

[46] *See* Resolution E-5217 (establishing uniform procedures to standardize the large energy utilities' annual end-of-year consolidated electric revenue for January 1 rate change advice letter filings to provide a more efficient process) Small jurisdictional IOUs subject to the requirements of SB 846 would follow the equivalent process for routine rate updates in their respective service territories (Aug. 4, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K459/496459720.PDF.

1. PG&E prepares an annual DCPP Forecast Application that is similar to but separate from the ERRA Forecast Application.

2. A Commission decision in the DCPP Forecast Application sets the level of the revenue requirement to be collected through the DCPP-specific NBC in each IOU's service territory.

3. That revenue requirement is translated to a $/kWh charge for eligible customers in an IOU's service territory in November and December via each IOU's consolidated rate change advice letter filing.

B. PG&E's DCPP Forecast Application Should Include Detailed Support of The Projected Net Costs to Be Charged Customers

As described earlier, PG&E is entitled to recover from customers the reasonable costs and expenses necessary to operate DCPP beyond the current expiration dates, net of market revenue from DCPP operation. The Commission should require PG&E to present detailed projections of all costs and revenues during DCPP extended operations in the annual DCPP Forecast Application. The presentation of costs and revenue included in the DCPP Forecast Application should be similar to the information provided in PG&E's GRC and ERRA proceedings. For example, PG&E should provide details of DCPP fixed costs by Major Work Category (**MWC**) and FERC account. Detailed generation output projections, nuclear fuel procurement costs, and other related forecast inputs should support forecasts for variable costs.

To incorporate the new SB 846 framework, the traditional DCPP revenue requirement calculation requires several changes. For example, SB 846 allows PG&E to recover all operating expenses and certain tax costs, but it is no longer allowed to record capital expenditures to rate base. Routine capital expenditures are to be recovered as operating expenses, and significant one-time capital expenditures may be amortized over more than one year as authorized by the Commission. Furthermore, several new fees will be charged to customers to compensate PG&E shareholders in lieu of a rate-based return on investments, including a volumetric performance-based fee of $13.00/MWh for each MWh generated by DCPP and a fixed payment of $100 million ($50 million per unit) annually. PG&E is also entitled to charge customers $12.5 million per month to fund a $300 million liquidated damages balancing account that can be used to cover the cost of replacement power during certain outages. Figure 4 provides an illustrative revenue requirement compilation, following a format consistent with the GRC and ERRA, demonstrating the calculation of DCPP net costs before and after adopting the changes that must be implemented pursuant to SB 846.

Figure 4

Line	Cost Category	Source	Current ($000)	SB 846 ($000)
1	**Operating Expenses**			
2	Production	2023 GRC; February Update	$315,173	$315,173
3	Transmission	2023 GRC; February Update	$4,283	$4,283
4	Uncollectibles	2023 GRC; February Update	$3,765	$3,765
5	Administrative and General	2023 GRC; February Update	$241,315	$241,315
6	Franchise & SFGR Tax Requirement	2023 GRC; February Update	$9,577	$9,577
7	Amortization	2023 GRC; February Update	$31,327	$31,327
8	Other Adjustments	2023 GRC; February Update	($1,142)	($1,142)
9	**Taxes**			
10	Property	2023 GRC; February Update	$19,669	$19,669
11	Payroll	2023 GRC; February Update	$18,735	$18,735
12	Business	2023 GRC; February Update	$264	$264
13	Other	2023 GRC; February Update	$4,964	$4,964
14	State Corporation Franchise	2023 GRC; February Update	$30,786	$30,786
15	Federal Income Tax	2023 GRC; February Update	$24,010	NA
16	**Other**			
17	Depreciation	2023 GRC; February Update	$409,011	NA
18	Other Revenue	2023 GRC; February Update	($4,684)	($4,684)
19	Employee Retention and License Renewal Costs	2023 ERRA/AL 5268-E; 5461-E-A	$53,192	$53,192
20	**SB 846 Items**			
21	Fixed Payment In Lieu of Rate-Based Return	PUC § 712.8(f)(6)		$100,000
22	Volumetric Payment In Lieu of Rate-Based Return	PUC § 712.8(f)(5)		$228,035
23	Liquidated Damages Balancing Acct Funding	PUC § 712.8(g), § 712.8(i)		$150,000
24	Replacement Power Costs	PUC § 712.8(i)		TBD
25	Incremental Decommissioning Planning	PUC § 712.8(f)(1), 712.8(f)(3)		TBD
26	Independent Review Panel Costs	PUC § 712.8(f)(4)		TBD
27	Annual Capital Expenditures	PUC § 712.8(h)(2)		TBD
28	**Return on Rate Base**			
29	Rate Base	2023 GRC; February Update	$1,952,370	NA
30	Rate of Return		7.34%	NA
31	Return on Rate Base	2023 GRC; February Update	$143,304	NA
32	**Variable Production Costs**			
33	Fuel	2021 FERC Form 1	$121,881	$121,881
34	**Total Costs**		**$1,425,430**	**$1,327,140**
35	**CAISO Market Revenue**			
36	2023 NP-15 Market Price ($/MWh)	2023 ERRA Energy Index	$84.22	$84.22
37	Annual Generation (GWh)	2021 FERC Form 1	17,541	17,541
38	**Total Wholesale Market Revenue**		**$1,477,318**	**$1,477,318**
39	**Net Costs**		**($51,887)**	**($150,178)**

In its May 19, 2023, Prepared Testimony (**DCPP Cost Testimony**) providing historical and forecast cost information for DCPP, PG&E presented limited cost information according to the Electric Utility Cost Group (**EUCG**) method which excludes several cost categories that PG&E considers corporate costs but that are assigned or allocated to DCPP for ratemaking purposes.[47] As operator of the plant, PG&E will continue to incur common corporate costs in support of DCPP extended operations, and these costs are appropriately recovered from customers through the DCPP NBC. PG&E acknowledged in its DCPP Cost Testimony that the annual cost recovery application for extended operations would include all costs relevant to DCPP operations, including common costs such as benefits, overhead, employee retention, regulatory compliance, and statutory charges and fees.[48] As such, PG&E should present its request for cost recovery in the DCPP Forecast Application in a manner consistent with the GRC and ERRA filings.

In addition, the Commission should require PG&E to demonstrate in its DCPP Forecast Application that its DCPP Forecast includes common cost assumptions that are consistent with its 2023 GRC. This GRC includes attrition years that extend beyond the original DCPP expiration dates to 2026 and assumes DCPP is retired.[49] For example, to determine the DCPP revenue requirement in its GRC PG&E allocates several categories of common corporate costs (*e.g.*, administrative and general expense) to DCPP using approved allocation factors. When asked in discovery, PG&E objected to providing details of the common costs allocated to DCPP in the 2023 GRC and opted not to explain whether actual common costs would be impacted by extended operations.[50] Because PG&E would not provide these additional details, Figure 4 contains only an illustrative

[47] PG&E Prepared Testimony (May 19, 2023) at 2:3-18.
[48] *Id*. at 16:1-13.
[49] PG&E Response to CalCCA Data Request 1.04.
[50] PG&E Responses to CalCCA Data Requests 1.05- 1.08.

revenue requirement using summarized cost categories from PG&E's GRC for the 2023 test period. In its DCPP Forecast Application, the Commission should require PG&E to quantify the impact of DCPP extended operations on its common costs relative to the amount approved in its 2023 GRC and demonstrate that there is no double counting of common costs proposed for recovery in the GRC and DCPP NBC.

Lastly, SB 846 states: "To the extent the commission decides to allocate any benefits or attributes from extended operations of the Diablo Canyon powerplant, the commission may consider the higher cost to customers in the operator's service area." [51] As a trade association with members that are both within and outside of "the operator's service area," CalCCA has a deep interest in finding the fairest way for the Commission to act upon such considerations.

Under SB 846, PG&E will assign a small portion of the costs authorized for recovery directly to customers of LSEs in its service territory. Those customers are also the sole beneficiaries of surplus wholesale market revenue and the return of excess funds paid into the liquidated damages balancing account by all customers. For example, half of the volumetric payment in lieu of a rate-based return ($6.50, in 2022 dollars, for each megawatt hour generated by DCPP during the period of extended operations)[52] is to be paid only by the customers of LSEs in PG&E service territory. In exchange for this cost responsibility, customers of LSEs in PG&E service territory will receive a credit for all surplus wholesale market revenue remaining after offsetting DCPP's annual operating costs.

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[51] Cal. Pub. Util. Code § 712.8(q).
[52] Cal. Pub. Util. Code § 712.8(f)(5).

Figure 5 is an illustrative division of net annual costs and revenue recovered from all customers versus those charged only to customers of LSEs in PG&E service territory. Notably, at current wholesale market prices it is possible that the total DCPP costs will be less than the total market revenue. In that case, PG&E will return the surplus revenue only to customers of LSEs in its service territory. Furthermore, even though customers of all LSEs in California will fund the liquidated damages balancing account ($12.5 million per month, up to a total balance of $300 million), funds remaining in the balancing account at the end of DCPP extended operations will be returned solely to customers of LSEs in PG&E service territory.[53]

[53] Cal. Pub. Util. Code §§ 712.8(g), 712.8(i), 712.8(u).

Figure 5

Line	Cost Category	Costs	Market Revenue	Net Costs
1	Operating Expenses	$604,298		
2	Taxes	$74,418		
3	Other	$48,508		
4	SB 846 Items			
5	Fixed Payment In Lieu of Rate-Based Return	$100,000		
6	Volumetric Payment In Lieu of Rate-Based Return	$114,018		
7	Liquidated Damages Balancing Acct Funding	$150,000		
8	Replacement Power Costs	TBD		
9	Incremental Decommissioning Planning	TBD		
10	Independent Review Panel Costs	TBD		
11	Annual Capital Expenditures	TBD		
12	Variable Production Costs	$121,881		
13	**Recovered From All Customers**	**$1,213,123**	**($1,213,123)**	**$0**
14	SB 846 Items			
15	Volumetric Payment In Lieu of Rate-Based Return	$114,018		
16	**Recovered From PG&E Service Territory Customers**	**$114,018**	**($264,195)**	**($150,178)**
17	**Grand Total**	**$1,327,140**	**($1,477,318)**	**($150,178)**
18	**CAISO Market Revenue**			
19	2023 NP-15 Energy Index ($/MWh)	$84.22		
20	Annual Generation (GWh)	17,541		
21	**Total Wholesale Market Revenue**	**$1,477,318**		

IV. THE NET COSTS OF DCPP EXTENDED OPERATIONS SHOULD BE TRACKED IN A NEW BALANCING ACCOUNT AND RECOVERED THROUGH A NEW NBC INCLUDED IN IOU DELIVERY RATES

As described earlier, PG&E currently recovers its costs to operate DCPP, both direct and indirect, through PCIA rates. To properly track and recover the net costs of DCPP extended operations, all related costs items should no longer be included in the PCIA but should be recorded in a new balancing account established specifically for this purpose.[54] PG&E has been developing parameters for the new balancing account, and

[54] Notably, in its 2024 ERRA Forecast application filed May 15, 2023, PG&E removed DCPP Unit 1 from the PCIA revenue requirement effective November 2024.

required subaccounts, to enable tracking and allocation of costs to appropriate LSEs; CalCCA largely supports PG&E's approach on this matter.

A. PG&E Has Already Developed A New Balancing Account to Record The Net Costs of DCPP Extended Operations

PG&E proposed the Diablo Canyon Extended Operations Balancing Account (**DCEOBA**) in Advice Letter (**AL**) 6870-E to track the costs during DCPP extended operations. CalCCA reviewed PG&E's proposed tariff statements as part of the AL 6870-E process, and PG&E incorporated CalCCA's feedback into the tariff language. CalCCA supports using the DCEOBA to track DCPP extended operations cost recovery as long as the tariff language accommodates recording all common costs that may be allocated to DCPP. CalCCA agrees with PG&E's proposal to allocate cost responsibility by IOU service territory in separate subaccounts of the DCEOBA.

B. A New NBC Should Be Created and Charged to Customers in Jurisdictional IOUs' Delivery Rates

California Public Utilities Code Section 712.8(I)(1) specifies, "The recovery of these non-bypassable costs by the [LSEs] shall be based on each customer's gross consumption of electricity regardless of a customer's net metering status or purchase of electric energy and service from an [ESP], [CCA], or other third-party source of electric energy or electricity service." As such, each IOU will need to implement its own NBC and remit to PG&E the revenue received through the charge.

As described earlier in my testimony, one outcome of PG&E's DCPP Annual Forecast will be an allocation of the net costs of DCPP extended operations for the upcoming year by IOU service territory. To develop the DCPP NBC, each IOU would first need to allocate its share of DCPP costs among its unique customer classes. The net costs by customer class would then be divided by the forecast class energy consumption to develop a $/kWh rate. Similar to the allocation across service territories, DCPP costs should be allocated among customer classes using each customer class's contribution to 12-month coincident peak. This is also the approach currently used to develop CAM surcharges. On an annual basis, each IOU should submit its DCPP NBC proposal for Commission approval and implementation in rates through the annual consolidated rate change advice letter process.

This concludes my testimony.

ATTACHMENT A

CURRICULUM VITAE OF BRIAN DICKMAN

NewGen Strategies & Solutions

Brian Dickman

PARTNER
BDICKMAN@NEWGENSTRATEGIES.NET

Mr. Brian Dickman is a partner in NewGen's energy practice with 20 years of utility industry experience. Mr. Dickman's career includes over a decade working for PacifiCorp, a vertically integrated investor-owned utility, including senior-level positions in regulatory, financial, and commercial roles. He began consulting in 2017, assisting a wide array of clients across the United States and internationally, including utilities, large consumers, and private investment firms. Mr. Dickman has extensive experience preparing and evaluating utility revenue requirements and cost allocation studies, developing utility avoided costs, and analyzing the impact of new initiatives and transactions on a utility and its customers. In addition to his extensive technical experience, Mr. Dickman understands the regulatory governance process, and he has personally testified as an expert witness before state public utility commissions in California, Idaho, Indiana, Oregon, Utah, Washington, and Wyoming.

Mr. Dickman advises numerous Community Choice Aggregator (CCA) clients in California, focusing on regulatory and rate issues such as the state-mandated exit fee known as the Power Charge Indifference Adjustment (PCIA). He also represents California CCAs as a member of the Cost Allocation Mechanism Procurement Review Groups for PG&E and Southern California Edison established by the California Public Utility Commission to provide an independent review of the centralized procurement of local generation capacity requirements.

EDUCATION

- Master of Business Administration, Finance Emphasis, University of Utah
- Bachelor of Science, Accounting, Utah State University

KEY EXPERTISE

- Cost of Service and Rates
- Financial Analysis and Modeling
- Power Charge Indifference Amount
- Regulatory Strategy
- Revenue Requirement

RELEVANT EXPERIENCE

Electric Cost of Service, Rate Design, and Regulatory Analysis

Mr. Dickman leads projects developing utility revenue requirements, preparing cost of service and rate design studies, and performing financial and regulatory analyses for electric utilities. Mr. Dickman previously held leadership positions at a multi-billion-dollar utility. He was responsible for interfacing with state regulatory agencies in support of revenue requirements, cost recovery mechanisms, avoided costs, valuations of potential asset acquisitions and other commercial opportunities, and financial impacts of utility initiatives. Mr. Dickman now works with clients and stakeholders to prepare pro forma financial models to determine revenue sufficiency, evaluate the cost of service studies and rate design proposals, and support such proposals before local and state governing bodies. Mr. Dickman's experience also includes evaluating the financial and rate impact of proposed mergers and acquisitions, acquisition and divestiture of utility assets, negotiated retail service contracts, changing business models, and stranded costs due to exiting load.

Brian Dickman

PARTNER

Expert Witness and Litigation Support

Mr. Dickman provides comprehensive expert witness testimony related to utility revenue requirements, cost of service, rate design, and other ratemaking issues before state and local regulatory bodies. He has provided litigation support in wholesale and retail jurisdictions, including California, Idaho, Indiana, Oregon, Washington, Wyoming, Utah, the Federal Energy Regulatory Commission, and Ontario Energy Board. Mr. Dickman offers expert witness testimony and litigation support in the following areas.

Revenue Requirement | Cost Allocation | Rate Design

Mr. Dickman prepared revenue requirements, inter-jurisdictional cost allocation, coincident peak allocation studies, and supporting testimony for PacifiCorp over many years. He now provides litigation support and expert testimony for clients wishing to review utility filings on revenue requirement, cost allocation, and rate design, including program-specific rate tariffs.

Power Supply Costs | Stranded Costs | Rate Adjustment Mechanisms

Mr. Dickman has prepared and evaluated variable power supply cost forecasts, power supply cost balancing accounts and other rate mechanisms, stranded costs, and exit fees for departing load. Since 2019, Mr. Dickman has actively participated in PCIA matters in California on behalf of CCA clients.

Avoided Costs | Resource Valuation

Mr. Dickman provided expert testimony for PacifiCorp on various components included in a proposed method for valuing solar generation resources, the calculation of Public Utility Regulatory Policies Act avoided costs for large resources, and support of modifications to the avoided cost calculation for small resources.

A sample of Mr. Dickman's utility clients includes the following:

- Abu Dhabi Distribution Company, UAE
- Central Coast Community Energy, CA
- City and County of San Francisco, CA
- Clean Power Alliance, CA
- Duke Energy, NC
- East Bay Community Energy, CA
- Hydro One, Ontario, CA
- Liberty Utilities, CA
- Lubbock Power and Light, TX
- Minnesota Power, MN
- New York Power Authority, NY
- Portland General Electric, OR
- San Diego Community Power, CA
- San Jose Clean Energy, CA
- Silicon Valley Clean Energy Authority, CA
- Vermont Gas Systems, VT

A sample of Mr. Dickman's non-utility clients includes the following:

- Blackstone Group, NY
- California Community Choice Association, CA
- Facebook, CA
- Hemlock Semiconductor, MI
- Newmont Mining, NV
- SABIC Innovative Plastics, IN
- Tri-County Metropolitan Transportation District, OR
- Vistra Energy, TX

WORKSHOPS AND PRESENTATIONS

Host organizations and the topics Mr. Dickman presented are displayed below.

Customer Choice at a Vertically Integrated Utility
Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, 2018

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. SCE	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting response to petition for modification of D.15-01-051, addressing changes to optional green tariff program rates	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority	2022
2. SCE	A.22-05-014	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority, and Central Coast Community Energy	2022
3. PG&E, SCE, SDG&E	A.20-02-009 A.20-04-002 A.20-06-001 (Consolidated)	Expert testimony evaluating the unrealized sales volumes and revenue due to Public Safety Power Shutoff events	California Public Utilities Commission	CCA Parties (9 individual CCAs)	2022
4. San Diego Gas & Electric	A.21-09-001	Expert testimony responding to proposed residential electrification tariff	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2022
5. San Diego Gas & Electric	R.20-05-003	Declaration supporting motion for clarification of D.19-11-016, quantifying impact to allocated incremental reliability procurement requirement due to departing load	California Public Utilities Commission	San Diego Community Power	2021
6. Southern California Edison	A.21-06-003	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2021
7. Pacific Gas & Electric	A.21-06-001	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2021
8. San Diego Gas & Electric	A.21-04-010	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2021
9. Pacific Gas & Electric	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting petition for modification of D.15-01-051, recommending changes to optional green tariff program rates designed to avoid shifting costs of resource capacity to non-participants	California Public Utilities Commission	Joint Community Choice Aggregators	2021

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
10. Pacific Gas & Electric	A.19-11-019	Expert testimony (adopted) addressing use of marginal costs to determine economic development rates and responding to proposed electrification tariff for retail customers	California Public Utilities Commission	Joint Community Choice Aggregators	2021
11. Pacific Gas & Electric	A.20-07-002	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2020
12. Southern California Edison	A.20-07-004	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2020
13. Pacific Power	Docket UE 375	Joint testimony supporting a settlement agreement resolving the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	Facebook, Inc.	2020
14. Pacific Gas & Electric	A.20-02-009	Expert testimony evaluating the appropriateness of entries recorded to the Portfolio Allocation Balancing Account to true up the Power Charge Indifference Amount	California Public Utilities Commission	Joint Community Choice Aggregators	2020
15. Vectren Energy Delivery of Indiana	Cause No. 43354 MCRA 21 S1	Expert testimony supporting a settlement agreement regarding the calculation and use of a 4CP load study to allocate tariff rider costs among customer classes	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mt. Vernon, LLC	2020
16. PacifiCorp	Docket UE 307	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2016
17. PacifiCorp	Docket UM 1662	Joint testimony with Portland General Electric regarding the need for a renewable resource tracking mechanism to provide cost recovery related to the impacts of renewable resource generation	Public Utility Commission of Oregon		2015
18. PacifiCorp	Docket UE 296	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2015

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
19. PacifiCorp	Docket No. 20000-469-ER-15	Expert testimony regarding the annual variable power supply cost forecast and modifications to the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2015
20. PacifiCorp	Docket No. 15-035-03	Provided expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2015
21. PacifiCorp	Docket UM 1716	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Utility Commission of Oregon		2015
22. PacifiCorp	Docket No. 20000-481-EA-15	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Service Commission of Wyoming		2015
23. PacifiCorp	Docket No. 15-035-T06	Expert testimony updating standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Public Service Commission of Utah		2015
24. PacifiCorp	Case No. PAC-E-15-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resource	Idaho Public Utilities Commission		2015
25. PacifiCorp	Docket UE-144160	Declaration supporting updates to standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Washington Utilities and Transportation Commission		2014
26. PacifiCorp	Docket UE 287	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2014
27. PacifiCorp	Case No. PAC-E-14-01	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2014
28. PacifiCorp	Docket A.14-08-002	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2014
29. PacifiCorp	Docket No. 20000-447-EA-14	Expert testimony regarding the true up of annual variable power supply cost in the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2014

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
30. PacifiCorp	Docket No. 14-035-31	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2014
31. PacifiCorp	Case No. PAC-E-13-03	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2013
32. PacifiCorp	Docket A.13-08-001	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2013
33. PacifiCorp	Docket No. 13-035-32	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2013
34. PacifiCorp	Docket UM 1610	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Public Utility Commission of Oregon		2012
35. PacifiCorp	Docket A.12-08-003	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2012
36. PacifiCorp	Docket No. 12-035-67	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2012
37. PacifiCorp	Docket No. 20000-389-EP-11	Expert testimony regarding the collection of deferred balances accrued through previous Power Cost Adjustment Mechanisms	Public Service Commission of Wyoming		2011
38. PacifiCorp	Docket No. 20000-405-ER-11	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2011
39. PacifiCorp	Case No. GNR-E-11-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Idaho Public Utilities Commission		2011
40. PacifiCorp	Case No. PAC-E-06-10	Expert testimony regarding low income customer weatherization rebates	Idaho Public Utilities Commission		2010

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
41. PacifiCorp	Docket No. 20000-405-ER-10	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2010
42. PacifiCorp	Docket No. 10-035-89	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Utah		2010
43. PacifiCorp	Docket No. 20000-352-ER-09	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2009
44. PacifiCorp	Case No. PAC-E-08-07	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Idaho Public Utilities Commission		2008
45. PacifiCorp	Docket No. 20000-333-ER-08	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2008

ATTACHMENT B

SELECT DATA RESPONSES

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q001		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q001		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley / Tom Baldwin	Requester:	Nikhil Vijaykar

QUESTION 001

Please identify all accounting mechanisms (including balancing accounts, memorandum accounts, etc.) PG&E relies on to record costs related to Diablo Canyon operation, maintenance, licensing, and decommissioning and retirement.

ANSWER 001

PG&E currently relies on the following active accounting mechanisms to record costs and cost recovery related to Diablo Canyon Power Plant's (DCPP) operations as follows:

Portfolio Allocation Balancing Account (PABA)

The purpose of this balancing account is to recover all "above-market" costs from all generation resources eligible for recovery through Power Charge Indifference Adjustment (PCIA) rates. This includes several different operational activities as found in PG&E's Electric Preliminary Statement Part HS and described further below:[1]

Utility-Owned Generation Revenue Requirements

PABA recovers the base revenue requirements associated with DCPP's operations, maintenance, and capital recovery as identified in PG&E's general rate case (as one of several utility-owned generation facilities). PABA also recovers specific revenue requirements related to the DCPP Retention Program and DCPP license renewal costs associated with relicensing costs for the current operating license period (i.e., prior to SB 846). Please see Electric Preliminary Statement Part HS, Tariff Lines 5.n., 5.p through 5.r. for relevant entries related to Utility-Owned Generation revenue requirements.

1 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HS.pdf.

CAISO-Related Entries

PABA also records relevant CAISO activity. This includes energy market revenues from scheduling and/or bidding DCPP into the CAISO market net of any miscellaneous or site-specific load that is also incurred for DCPP. Please see Electric Preliminary Statement Part HS, Tariff Lines 5.t. through 5.v. for relevant CAISO-related entries.

Fuel Costs

In addition, PABA is authorized to recover nuclear fuel expenses and miscellaneous expenses for DCPP, as well as carrying costs on PG&E's net outstanding nuclear fuel inventory at the rate of the three-month commercial paper rate. Please see Electric Preliminary Statement Part HS, Tariff Lines 5.z. and 5.aa. for relevant nuclear fuel entries.

Note: Recovery within PABA is included through the current licensing period and will not include extension period activity.

Nuclear Decommissioning Adjustment Mechanism (NDAM)

This account recovers authorized nuclear decommissioning revenue requirements and to provide full recovery of costs. In addition, the approved tariff includes recovery of other related expenses including costs to satisfy the requirements of CA Bill 968 and Public Utilities Code Section 712.5 Section 3, DCPP Employee Retraining Program budget, and authorized recovery of funds approved in the Community Impact Mitigation Program (CIMP). Detailed accounting entries can be found in PG&E's Electric Preliminary Statement Part DB.[2]

Diablo Canyon Retirement Balancing Account (DCRBA)

This account is used to track actual expenses and capital revenue requirements against expense budgets or capital revenue requirements related to (1) DCPP full book value by the time Units 1 & 2 cease operations, (2) the DCPP Employee Retention Program, and (3) the DCPP Employee Retraining Program. The differences are transferred to PABA or NDAM as applicable and as authorized by the Commission. Detailed entries can be found in PG&E's Electric Preliminary Statement Part HK.[3]

Nuclear Regulatory Commission Rulemaking Balancing Account (NRCRBA)

This account is used for recovery of actual expenses for complying with existing, emerging or evolving NRC regulations and directives. These costs include but are not limited to, the following four major NRC rulemaking processes currently in progress: Fukushima Daiichi Rulemaking, Cyber-Security Rulemaking, Emergency Planning

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2 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_DB.pdf.

3 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HK.pdf.

Rulemaking, and the new National Fire Protection Standard (NFPA) 805 Rulemaking. Detailed entries can be found in PG&E's Electric Preliminary Statement Part GM.[4]

Department of Energy Litigation Balancing Account (DOELBA)

This account tracks and records for customers of any proceeds, net of costs, from PG&E's lawsuit against the Department of Energy (DOE) filed in the Federal Court of Claims on January 22, 2004, regarding the DOE's breach of spent fuel contracts and any additional claims for reimbursement that PG&E may have against DOE arising out of or related to spent fuel contracts. This account ensures the proper crediting and allocation of proceeds and costs for the benefit of customers as determined by the Commission between the Diablo Canyon and Humboldt Bay nuclear power plants. The DOELBA will expire after litigation is completed, proceeds have been received, and the Commission has authorized disposition of the balance. Amounts get transferred to PABA or NDAM as authorized by the Commission. Detailed entries can be found in PG&E's Electric Preliminary Statement Part DZ.[5]

Additional mechanisms related to costs for extend operations of DCPP in accordance with SB 846 were proposed as part of PG&E's Advice Letter 6870-E and Supplemental Advice Letter 6870-E-A, currently pending disposition from the Commission.

4 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_GM.pdf

5 Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_DZ.pdf

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q002		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q002		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley	Requester:	Nikhil Vijaykar

QUESTION 002

Please identify all rate mechanisms currently relied on by PG&E to recover any costs related to Diablo Canyon and describe the costs included in each mechanism.

ANSWER 002

PG&E currently recovers costs associated with Diablo Canyon through two nonbypassable charges:

- Power Charge Indifferent Adjustment (PCIA) rates
- Nuclear Decommissioning rates

PCIA revenues are credited to the Portfolio Allocation Balancing Account (PABA). Nuclear Decommissioning revenues are credited to the Nuclear Decommissioning Adjustment Mechanism (NDAM). Please see PG&E's response to Question 1 of this data request for further details on the activities recovered within PABA and NDAM, as well as other accounts transferred to PABA and NDAM for cost recovery.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q004		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q004		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Brian Ketelsen	Requester:	Nikhil Vijaykar

QUESTION 004

Please confirm that PG&E’s 2023 GRC assumes the Diablo Canyon Power Plant is retired in 2024 (Unit 1) and 2025 (Unit 2). If not confirmed, please explain.

ANSWER 004

PG&E objects to this data request as irrelevant and outside the scope of this proceeding. Subject to and without waiving that objection, PG&E confirms that PG&E’s 2023 GRC assumes DCPP is retired in 2024 (Unit 1) and 2025 (Unit 2).

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q005		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q005		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 005

Please quantify all common costs by category allocated to Diablo Canyon Power Plant revenue requirement in 2023, 2024, 2025, and 2026 as included in PG&E's February Update of its 2023 GRC. For each category, explain the basis for the total common costs and the method used to allocate costs to Diablo Canyon Power Plant.

ANSWER 005

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q006		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q006		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 006

Please explain whether the common costs identified in the previous request allocated to Diablo Canyon Power Plant prior to its retirement are assumed to be reallocated among other resources and/or departments after Diablo Canyon Power Plant retirement.

ANSWER 006

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q007		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q007		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 007

Please explain whether PG&E assumed a reduction in overall common costs through 2026 due to Diablo Canyon Power Plant retirement. If yes, please quantify the reduction by year and by category. If no, please explain why not.

ANSWER 007

PG&E objects to this data request as irrelevant and outside the scope of this proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q008		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q008		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 008

Please explain whether continued operation of Diablo Canyon Power Plant will cause PG&E common costs to be higher than projected in 2025 and 2026 relative to the amount assumed in PG&E's GRC. If yes, please quantify the incremental common costs by year and category. If not, please explain.

ANSWER 008

PG&E objects to this data request on grounds that PG&E's GRC costs are irrelevant and outside the scope of this proceeding.

Notwithstanding this objection, PG&E's May 19, 2023, Testimony in Rulemaking (R.) 23-01-007, Table 2, presents cost forecasts through 2030 that include accounting categories adopted by the Electric Utility Cost Group (EUCG). The "Support Services" line item includes costs for organizations outside of DCPP such as Information Technology, Insurance, Legal, Finance, Executive Leadership, Communications, Safety and Health, Procurement, and Human Resources.

These organizations have separate GRC chapters and are not included in the Nuclear chapter in PG&E's most recent GRC Application, Application 21-06-021 and therefore could be considered common costs supporting Diablo Canyon.

Of note, the EUCG cost presentation in PG&E's May 19, 2023, Testimony does not capture items such as property taxes, depreciation, interest expense, and revenues.

CAC Item C4E
Consent Item 8

TO: East Bay Community Energy Board of Directors

FROM: Marie Fontenot, Vice President of Power Resources

SUBJECT: **Ratifying Resolution No. R-2023-18, Clarifying and Affirming that such Board authorization includes the CEO's authority to negotiate and execute an agreement with MRP Pacifica Marketing, LLC regarding the 16 MW/MWh battery storage project in Kings County (Action)**

DATE: September 20, 2023

Recommendation

Adopt one Resolution ratifying Resolution No. R-2023-18, clarifying and affirming that such Board authorization includes the CEO's authority to negotiate and execute an agreement with MRP Pacifica Marketing, LLC regarding the 16 MW/MWh battery storage project in Kings County and authorizing CEO take necessary action to implement such project. The project components and operational date are detailed below:

a. Malaga: This encompasses a 15-year, financial hedge and RA from a co-located 96 MW natural gas peaker, a 96MW/96MWh battery storage project in Fresno County, CA, and a 16MW/64MWh battery storage project in Kings County. The expected online date for the battery projects is April 1, 2024. The project is developed by Middle River Power, LLC.

Background and Discussion

The 2022 Long-Term Resource Request for Offers (RFO) is EBCE's second long-term contract solicitation. The RFO was launched in February 2022. The RFO sought several hundred megawatts (MW) of contracts with renewable energy and battery storage projects with a preference for projects located in California, and more preferentially, those located in Alameda County. EBCE's objective was to drive investments in new renewable and energy storage projects in Alameda County and California, while securing affordable resources to manage future power price risk. EBCE received a very healthy response to its RFO both in volume and quality of projects and proposals. EBCE administered the RFO and completed robust analytics using internal tools and the cQuant valuation platform to calculate the net present value of proposed projects and determine the optimal portfolio to meet its objectives. All of these contracts will be utilized to hedge EBCE against price fluctuation in the CAISO energy markets and they will also contribute to procurement mandates issued by the California Public Utilities Commission (CPUC). The 2021-2023 Electric Reliability Requirements procurement mandate identified volumes of RA capacity each CPUC-jurisdictional load serving entity must procure and have online in the years 2021, 2022 and 2023.[1] The second mandate requires additional volumes of RA come online in years 2023, 2024, 2025, and 2026. That mandate is the "Decision Requirement Procurement to Address Mid-Term Reliability 2023-2026".[2]

The 16MW/64MWh battery storage project in Kings County was described in the staff report associated with R-2023-18 and was highlighted in a recital. However, it was inadvertently omitted from the Board action section of the Resolution. This current recommendation seeks to rectify this oversight.

The Malaga project is a financial hedge and RA agreement. It will be comprised of a co-located 96MW natural gas peaking facility and a 96MW/96MWh battery storage project in Fresno County and a 16MW/64MWh battery storage facility in Kings County. The natural gas peaking facility is already built and operational; the battery is new and not yet developed. The contract is for 15 years with an expected commercial operation date of April 1, 2024. Middle River Power is an experienced developer and project owner having numerous operating natural gas facilities in California. Middle River Power has executed a similar agreement with another CCA. The contracting entity is MRP Pacifica Marketing, LLC.

<u>Attachments</u>

A. Resolution Ratifying Resolution No. R-2023-18, Clarifying and Affirming that such Board authorization includes the CEO's authority to negotiate and execute an agreement with MRP Pacifica Marketing, LLC and authorizing CEO take necessary action to implement the 16MW/64MWh battery storage project with MRP Pacifica Marketing, LLC in Kings County.
B. Resolution No. R-2023-18.

[1] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF
[2] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF

RESOLUTION NO. R-2023-XX

A RESOLUTION OF THE BOARD OF DIRECTORS

OF THE EAST BAY COMMUNITY ENERGY AUTHORITY CLARIFYING BOARD AUTHORIZATION IN RESOLUTION NO. R-2023-18

WHEREAS The East Bay Community Energy Authority ("EBCE") was formed as a community choice aggregation agency ("CCA") on December 1, 2016, Under the Joint Exercise of Power Act, California Government Code sections 6500 *et seq.*, among the County of Alameda, and the Cities of Albany, Berkeley, Dublin, Emeryville, Fremont, Hayward, Livermore, Piedmont, Oakland, San Leandro, and Union City to study, promote, develop, conduct, operate, and manage energy-related climate change programs in all of the member jurisdictions. The cities of Newark and Pleasanton, located in Alameda County, along with the City of Tracy, located in San Joaquin County, were added as members of EBCE and parties to the JPA in March of 2020. The city of Stockton, located in San Joaquin County was added as a member of EBCE and party to the JPA in September of 2022.

WHEREAS EBCE issued the 2020 Long-Term Resources request for offers (RFO) in October 2020;

WHEREAS EBCE re-evaluated the previously offered project while negotiating contracts from the 2022 RFO and saw new value in the unique commercial structure;

WHEREAS MRP Pacifica Marketing, LLC, proposed a Financial Hedge and RA Agreement for a co-located 96MW natural gas peaking facility and a 96MW/96MWh battery storage project in Fresno County and a 16MW/64MWh battery storage project in Kings County, developed by Middle River Power;

WHEREAS the project is expected to be operational by April 1, 2024 and will provide a financial hedge and Resource Adequacy (RA) for the term of fifteen years;

WHEREAS on March 15, 2023, the EBCE Board of Directors adopted Resolution No. R-2023-18 authorizing the CEO to negotiate and execute a fifteen-year financial hedge and RA Agreement with MRP Pacifica Marketing, LLC for a co-located 96MW natural gas peaking facility and a 96MW battery energy storage project in Fresno County;

WHEREAS the 16MW/64MWh battery storage project in Kings County was described in the staff report associated with R-2023-18 and called out in a recital but was inadvertently omitted from the Board action section of the Resolution; and

WHEREAS the Board of Directors would like to clarify and affirm that the Board authorization in Resolution No. R-2023-18 includes the 16MW/64MWh battery storage project in Kings County.

NOW, THEREFORE, THE BOARD OF DIRECTORS OF THE EAST BAY COMMUNITY ENERGY AUTHORITY DOES HEREBY RESOLVE AS FOLLOWS:

Section 1. The EBCE Board of Directors hereby ratifies Resolution No. R-2023-18, clarifying and affirming that such Board authorization includes the CEO's authority to negotiate and execute an agreement with MRP Pacifica Marketing, LLC for a 16MW/64MWh battery storage project in Kings County.

Section 2. The EBCE Board of Directors hereby authorizes the CEO to take any necessary action to implement the 16MW/64MWh battery storage project in Kings County.

ADOPTED AND APPROVED this 20th day of September, 2023.

____

Elisa Márquez, Chair

ATTEST:

____

Adrian Bankhead, Clerk of the Board

Staff Report Item 12

TO: East Bay Community Energy Board of Directors

FROM: Marie Fontenot, Vice President of Power Resources

SUBJECT: **Middle River Power Malaga Contract Approval (Action)**

DATE: March 15, 2023

Recommendation

Adopt a Resolution authorizing the Chief Executive Officer to finalize negotiations and execute an Agreement with contracting entity MRP Pacifica Marketing, LLC for the Malaga contract. The Malaga contract is a 15-year, multi-product agreement comprised of a financial hedge backed by physical resources and RA from a co-located existing natural gas peaker plant and an incremental battery storage project in Fresno County as well as RA from an incremental battery storage project in Kings County, CA. with April 1, 2024 as the date for contract deliveries to begin. The project is being developed by Middle River Power, LLC.

Background and Discussion

The 2022 Long-Term Resource Request for Offers (RFO) is EBCE's third long-term contract solicitation. The RFO was launched in February 2022. The RFO sought several hundred megawatts (MW) of contracts with renewable energy and battery storage projects with a preference for projects located in California, and more preferentially, those located in Alameda County. EBCE's objective was to drive investments in new renewable and energy storage projects in Alameda County and California, while securing affordable resources to manage future power price risk. EBCE received a healthy response to its RFO both in volume and quality of projects and proposals. EBCE administered the RFO and completed robust analytics using internal tools and the cQuant valuation platform to calculate the net present value of proposed projects and determine the optimal portfolio to meet its objectives. All of these contracts will be utilized to hedge EBCE against price fluctuation in the CAISO energy markets and they will contribute to procurement mandates issued by the California Public Utilities

Commission (CPUC). The 2021-2023 Electric Reliability Requirements procurement mandate identified volumes of RA capacity each CPUC-jurisdictional load serving entity must procure and have online in the years 2021, 2022 and 2023.[1] The second mandate requires additional volumes of RA come online in years 2023, 2024, 2025, and 2026. That mandate is the "Decision Requirement Procurement to Address Mid-Term Reliability 2023-2026".[2]

The Malaga contract is comprised of multiple products and three resources; the deal structure includes a financial hedge backed by physical resources and two RA agreements. The Malaga contract was originally offered to EBCE in its 2020 RFO but was re-evaluated during the 2022 RFO process. Staff sees value to this unique mixture of products: a financial hedge offered in part by an existing asset is especially valuable in the current climate: supply chain problems continue to delay the construction of new facilities and investor-owned utilities experience delays in their ability to interconnect new generating resources, and RA provided by a natural gas plant will contribute to EBCE's position and is needed as the RA rules undergo redesign. The hedge is intended to provide financial coverage, a form of insurance policy, for EBCE during the highest demand periods of the year and will provide some coverage of EBCE's open position. The proposed hedge structure is a financial transaction only, EBCE will not take possession of or title to the energy generated by the natural gas plant or the energy charged and discharged by the co-located battery; as such the transaction will not add emissions to EBCE's portfolio.

The physical resources that comprise the contract are a co-located 96MW natural gas peaking facility and a 96MW/96MWh battery storage project in Fresno County and an additional 16MW/64MWh battery storage project in Kings County. The natural gas peaking facility is existing; the batteries are new and not yet developed. The 96MW battery storage project co-located with the gas plant is noteworthy in the addition of this new resource is intended to result in reduced dispatch of the co-located natural gas peaking facility by the CAISO market. The contract is for 15 years with is expected to begin delivery on April 1, 2024. Middle River Power is an experienced developer and project owner having numerous operating natural gas facilities in California. Middle River Power has executed a similar agreement with another CCA. The contracting entity is MRP Pacifica Marketing, LLC.

Attachments

A. Resolution Authorizing the CEO to Negotiate and Execute a Fifteen-Year Financial Hedge and RA Agreement with MRP Pacifica Marketing, LLC.
B. PowerPoint Presentation

[1] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF
[2] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF

RESOLUTION NO. R-2023-XX

A RESOLUTION OF THE BOARD OF DIRECTORS

OF THE EAST BAY COMMUNITY ENERGY AUTHORITY AUTHORIZING THE CEO TO NEGOTIATE AND EXECUTE A DISPATCHABLE ENERGY AND ENERGY STORAGE AGREEMENT WITH MRP PACIFICA MARKETING, LLC

WHEREAS The East Bay Community Energy Authority ("EBCE") was formed as a community choice aggregation agency ("CCA") on December 1, 2016, Under the Joint Exercise of Power Act, California Government Code sections 6500 *et seq.*, among the County of Alameda, and the Cities of Albany, Berkeley, Dublin, Emeryville, Fremont, Hayward, Livermore, Piedmont, Oakland, San Leandro, and Union City to study, promote, develop, conduct, operate, and manage energy-related climate change programs in all of the member jurisdictions. The cities of Newark and Pleasanton, located in Alameda County, along with the City of Tracy, located in San Joaquin County, were added as members of EBCE and parties to the JPA in March of 2020.

WHEREAS EBCE issued the 2020 Long-Term Resources request for offers (RFO) in October 2020;

WHEREAS EBCE re-evaluated the previously offered project while negotiating contracts from the 2022 RFO and saw new value in the unique commercial structure;

WHEREAS MRP Pacifica Marketing, LLC, proposed a Financial Hedge and RA Agreement for a co-located 96MW natural gas peaking facility and a 96MW/96MWh battery storage project in Fresno County and a 16MW/64MWh battery storage project in Kings County, developed by Middle River Power, and

WHEREAS the project is expected to be operational by April 1, 2024 and will provide a financial hedge and Resource Adequacy (RA) for the term of fifteen years.

NOW, THEREFORE, THE BOARD OF DIRECTORS OF THE EAST BAY COMMUNITY ENERGY AUTHORITY DOES HEREBY RESOLVE AS FOLLOWS:

Section 1. The CEO is hereby authorized to negotiate and execute a fifteen-year financial hedge and RA Agreement with MRP Pacifica Marketing, LLC for a co-located 96MW natural gas peaking facility and a 96MW battery energy storage project in Fresno County. The final agreement shall include the key terms outlined in the Staff Report associated with this Resolution.

ADOPTED AND APPROVED this 15th day of March, 2023.

Elisa Marquez, Chair

ATTEST:

Adrian Bankhead, Clerk of the Board

Attachment Consent Item 8B
Attachment Staff Report Item 12B

EAST BAY COMMUNITY ENERGY

Bilateral Contract for Board Consideration

PRESENTED BY: Marie Fontenot

DATE: March 15, 2023

Agenda

- Context:
  - Recent 2022 RFO Solicitation Overview
  - 2022 RFO Participation
  - Evaluation Process
- Current RFO Portfolio Characteristics
- Projects Proposed for Execution
- Challenges in Marketplace
- Next Steps
- Appendix: Portfolio Summary

Solicitation Overview

Goals & Objectives

- Secure a portfolio of contracts to provide EBCE customers with affordable renewable and clean energy sources
- Meet IRP Near- and Mid-Term Resource Adequacy Reliability Procurement mandates
- Meet a significant percent of SB350 long-term contracting requirements, equal to 65% of RPS obligations
- Create new renewable energy projects to deliver PCC1 RECs
- Contract low-cost energy hedges to compliment existing portfolio
- Partner with SJCE for efficiency, to minimize expenses, and lead the market in contract terms

Project Characteristics

Facilities:

- Location: Projects may be within or outside of California. All energy must be deliverable to CAISO & must provide RA
- Construction Status: Energy and related products may come from new resources or add incremental capacity to existing resources.

Capacity:

- Minimum Contract Capacity: 5 MW
- Maximum Contract Capacity: none

Delivery Date:

- Energy and RPS attribute delivery must be within calendar years 2023, 2024, 2025, or 2026 with a preference for projects that begin delivery earlier within this window.

Contract Duration:

- 10-20 year durations

Technology:

- Renewables, Large Hydro
- Storage – short or long duration; any technology

Actions

- Issued a broad, open, competitive solicitation to ensure wide array of opportunities considered
- Evaluated combinations of projects to achieve desired volume targets
- Typically prioritize project risk, location, workforce development, economics, and other characteristics; limited ability to do so in this RFO due to limited offers in earlier years
- Encouraged RFO participants to be creative and provide proposal variations on individual projects and include battery storage

EAST BAY COMMUNITY ENERGY

Solicitation Overview – Eligible Products

Product #	Product Name	Description	Example
Product 1	As-Available RPS Product	New or incremental capacity to an existing stand-alone PCC1-eligible generating resource	solar, wind, geothermal, small hydro or ocean (thermal, wave, or current)
Product 2	As-Available RPS plus Energy Storage	New or incremental capacity to an existing stand-alone PCC1-eligible generating resource with co-located energy storage	Same as above plus storage with 2-hr, 4-hr, or 4-hr+ duration capability
Product 3	Firm or Shaped RPS Product	New PCC1-eligible generating resources; likely paired with energy storage	Energy delivered during specific hours
Product 4	High Capacity Factor, No On-Site Emissions RPS Energy	New stand-alone PCC1-eligible generating resource	Geothermal or Biomass
Product 5	Stand-Alone Energy Storage Toll or RA-Only offer	Energy storage may offer a full product “tolling” structure contract or and RA-only offer	Any storage technology with 2-hr, 4-hr, or 4-hr+ duration capability
Product 6	Zero-Emitting Capacity Resources	Must be available every day from 5pm to 10pm (hours ending 17 through 22); must be able to deliver <u>at least 5 MWh of energy for every 1 MW of incremental capacity</u>	Emission-free generation resources, emissions-free generation paired with storage, or demand response

Participation

- Less robust project offering than 2020 RFO. 44 unique project sites; 185 contract variations (as compared to 70 sites; 400 project variations in 2020 RFO)
- All 6 products that were solicited were offered
- Offers included solar, wind, geothermal, pumped hydro, and storage
- Projects based in 6 different states (CA, AZ, ID, NM, NV, OR); predominantly CA
  - **Only 1 projects in EBCE service territory.*

Evaluation Process

- **Evaluation Rubric scored 3 areas:**
  - Counterparty Execution, Offer Competitiveness, and Project Development Status
  - Multiple items under each area
- **Two reviewers were assigned to each project.**
- **Staff reviewed all submitted information and provided scores for all categories except for Term Sheet Markups and NPV.**
  - Each item has 10 point max. at its own weighting.
  - Term Sheet Markups were scored by one assigned reviewer.
  - NPV scores were directly incorporated into overall project score with a weighting of 45%.
    - The Net Present Value was calculated based on simulations on 3 different forward curves
    - For each forward curve we took a weighted average of the P5 (50%), P50 (25%), and P95 (25%) and then took a simple average across the 3 curves
    - We normalized this number on a $/MW basis and the projects were then assigned a 0-10 score based on the NPV distribution
- **Scoring and rubric were consistent with the selection process for the 2018 California Renewables RFP and 2020 RPS and Storage RFO.**

EAST BAY COMMUNITY ENERGY

2022 RFO Portfolio Characteristics

	Developer	Project	Location	Product	Offtake	COD	Nameplate	Sept NQC
Gener-ation	**Longroad**	**Sun Pond**	**Maricopa County, AZ**	**PV and ESA**	**EBCE**	**4/1/2025**	**85 MW**	**34.4**
Stor-age	**NextEra Energy**	**Kola Energy Storage**	**San Joaquin County (Tracy), CA**	**ESA**	**EBCE**	**6/1/2025**	**125 MW**	**116.75**
RA Only	**ConEd**	**Alpaugh BESS**	**Tulare County, CA**	**RA only**	**EBCE**	**6/1/2024**	**5 MW**	**4.5**
	Vitol	Ocotillo Solar	**San Diego County, CA**	RA only	EBCE	8/1/2023	50 MW	50
	Broad Reach Power	Noosa Energy Storage	**San Joaquin County, CA**	RA only	EBCE & SJCE	6/1/2024	30 MW	27
	Broad Reach Power	Cascade Energy Storage	**San Joaquin County, CA**	RA only	EBCE & SJCE	6/1/2024	5 MW	4.5

EAST BAY COMMUNITY ENERGY

"Existing" Portfolio Summary

DEVELOPER	PROJECT NAME	TECHNOLOGY	NAMEPLATE MW	STORAGE MW/MWH	COUNTY	ONLINE	TERM (YEARS)
Clearway Energy Group	Golden Fields Solar	Solar	112	N/A	Kern	December 2020	15
Greenbacker Capital	Scott Haggerty Wind Energy Center	Wind	57.5	N/A	Alameda	July 2021	20
Convergent Energy and Power	Henrietta D Energy Storage	Storage	0	10/40	Kings	January 2022	15
Pattern Energy	Tecolote Wind	Wind	100	N/A	Torrance and Guadalupe (NM)	December 2021	10
Idemitsu Renewables	Tulare Solar Center	Solar	56	N/A	Tulare	May 2022	15
Terra-Gen	Sanborn Storage	Storage	0	47/188	Kern	December 2022	12
EDP Renewables	EDPR Solar Park	Solar + Storage	100	30/120	Fresno	December 2022	20
Terra-Gen	Edwards Solar	Solar + Virtual Storage	100	TBD	Kern	December 2022	15
Clearway Energy Group	Daggett 3	Solar+ Storage	50	12.5/50	San Bernadino	April 2023	15
Intersect Power	Oberon	Solar+ Storage	125	125	Riverside	January 2024	10+
LS Power	Tumbleweed Energy Storage	Storage	0	50/200	Kern	June 2024	15

EAST BAY COMMUNITY ENERGY

Middle River Power – Malaga Dispatchable Energy and Energy Storage Project Details

- Originated and negotiated bilaterally. Originally offered into 2020 Renewable Resource and Energy Request for Offers (RFO).
- Financial Hedge back by physical assets and RA Agreement.
  - Existing gas peaker plant
  - Two new batteries
- 15-year contract
- Expected Initial Contract Delivery Date is April 1, 2024
- Project has an executed interconnection agreement.
- The contracting entity under Middle River Power (MRP) is MRP Pacifica Marketing, LLC.

MIDDLE RIVER POWER

Middle River Power Company Overview

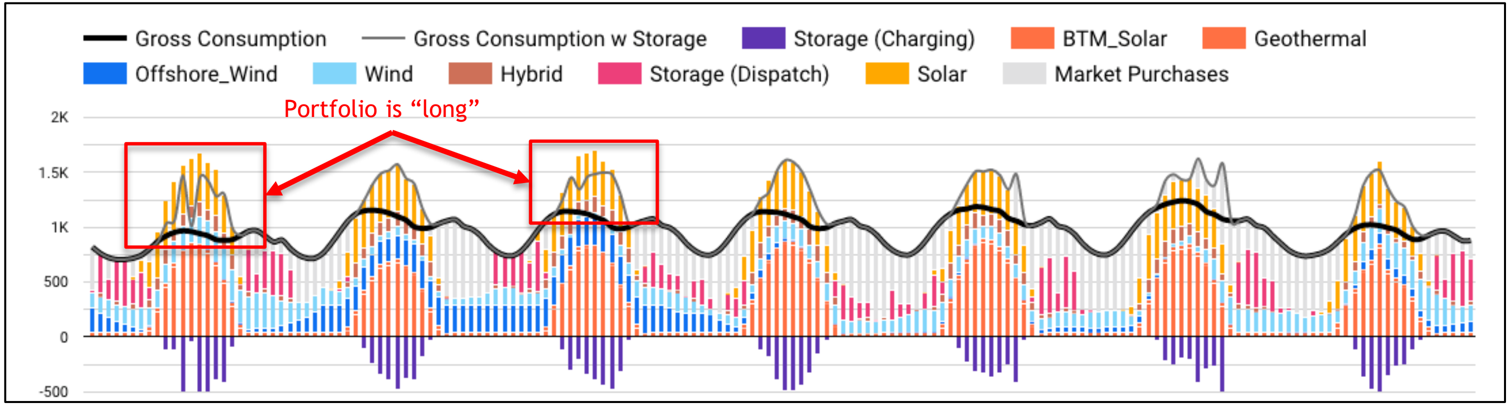
- Middle River Power is a private equity sponsored investment and asset management platform focused on US power generation assets.
- Middle River Power owns and operates 2300 MW of natural gas fired generation with 160 MW of peaker and 100 MW of solar in development within California and a combined total of over 3000 MW throughout the US.
- Middle River Power has 420 MW of co-located natural gas and battery storage in development within California.
- MRP has successfully developed and contracted several assets in California such as a 100 MW solar project with a 50 MW battery in Victorville, a 60 MW standalone battery, and a 130 MW geothermal project in Coso Junction, California
- Middle River Power is an experienced power owner and operator in California with several their projects contracted with PG&E ending in 2022.

EAST BAY COMMUNITY ENERGY

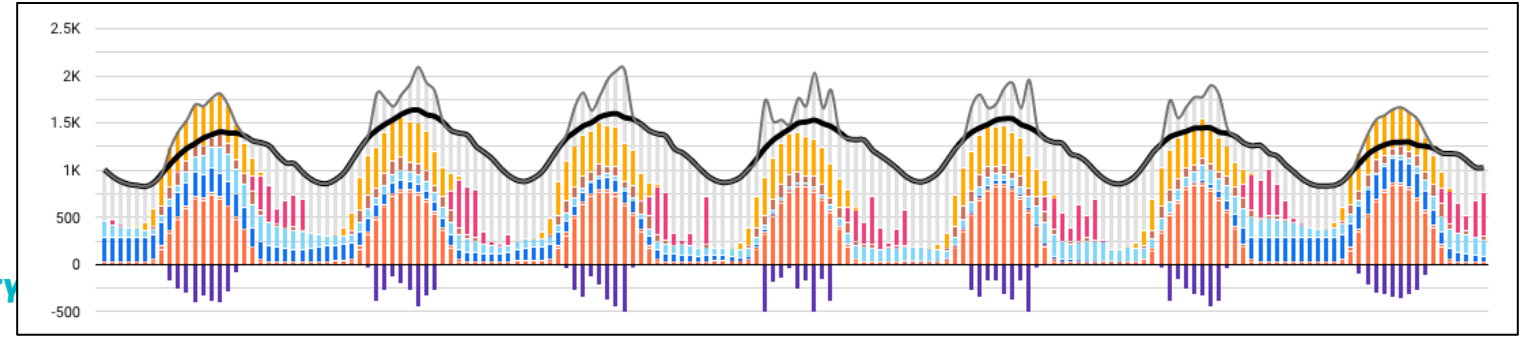
Example Portfolio – Market Exposure

- **Modeling exhibits a preference for portfolios that, on average, limit EBCE's sales of excess electricity into the market. This leads to periods of market reliance in "high load" months to limit exposure to low / negative prices in "lower load" months**

Sample week - April 2030



Sample week - July 2030



EAST BAY COMMUNITY ENERGY

Challenges in Marketplace

- Supply Chain
- Permitting Delays
- Interconnection Delays
- Risk of additional governmental intervention, similar to solar anti-circumvention investigation of 2022

Next Steps

- Finalize contract and execute agreements.
- Assess project as it hits key milestones and matures further.
- Update filing to CPUC on status of 2021-2023 and 2023-2026 Electric Reliability Requirements due June 1, 2023.

Appendix

CAC Item C4F
Consent Item 6

TO: East Bay Community Energy Board of Directors

FROM: Howard Chang, Chief Operating Officer & Treasurer

SUBJECT: **Energy Prepay Transaction #3 Summary of Results (Informational)**

DATE: September 20, 2023

Recommendation

Receive an informational item to summarize the results of EBCE's third energy prepay transaction.

Background and Discussion

On July 19, 2023, EBCE approved moving forward with its third energy prepay transaction. Working with Morgan Stanley as the bond underwriter, we successfully priced the bonds on August 9, 2023 and closed the prepay transaction on August 16, 2023.

Details of the transaction are below.

Total Bond Proceeds: $1,037,266,229.50

Start Date: Jan 1, 2024

Tenor of the initial bonds: 7 years

Cost of Issuance: 0.59%

Average Annual Savings for Initial Term: $6,931,707

Given the strong execution and opportune market timing, it is very notable that this has resulted in the highest savings discount on a MWh basis of $12.67/MWh of any Morgan Stanley Prepay to date. This transaction is EBCE's third prepay transaction. Together with the savings from EBCE's previous two prepay transactions, EBCE has secured annual savings of approximately $14MM, which represents roughly a 2% discount on energy costs to all EBCE customers. All three prepay transactions are 30 energy contracts. The savings from the second prepay transaction are locked in until 2031, which is when the bonds will need to be repriced, and the future discount will be based on market conditions at that time. The savings from the first transaction are locked in until 2032 because it closed on 10-year bonds and the savings from the second transaction are locked in until 2029 because it closed on 6-year bonds.

Through the energy prepay transaction this discount is being applied to a variety of long and short-term renewable energy and large hydro contracts that EBCE is assigning into the structure. Based on the number of eligible source-specified PPAs under contract, EBCE will seek to continue to execute additional prepay transactions in the coming years to maximize the available savings.

EBCE's board approved and adopted a resolution subject to the following parameters:

> (a) the Bonds will not be obligations of EBCE, but will be limited obligations of the Issuer payable solely from the revenues and other amounts pledged therefor under the Indenture, including amounts payable by EBCE under the Power Supply Contract;
>
> (b) the aggregate principal amount of the Bonds shall not exceed $1,000,000,000;
>
> (c) the annual energy savings to EBCE under the Power Supply Contract shall be at least $4.50 per MWh

The executed transaction complies with all aspects of the resolution with a principal amount of $997,895,000 and savings of over $12.67/MWh. Note that the principal amount of $997,895,000 is less than the proceeds of $1,037,266,229.50. This difference exists because the standard market coupon on bonds is 5%, but currently the market yield is in the 4% range. Therefore, the bonds are priced with a small premium, which increases the proceeds actually invested by bondholders at day 1.

Previous Background Information:

An energy prepayment is a long-term financial transaction available to municipal utilities and tax-exempt entities such as CCAs that enables a meaningful power procurement cost savings opportunity. This prepay structure has historically been utilized for natural gas procurement and is now being applied towards renewable energy. To date, EBCE, Silicon Valley Clean Energy (SVCE), MCE, CPA, and Pioneer Energy, have executed prepay transactions and currently a number of other CCAs are also in the process of initiating a similar structure.

Financial Impact

There is no financial impact related to receiving this informational item.

Attachments

None

CAC Item C5
Staff Report Item 13

TO: East Bay Community Energy Board of Directors

FROM: Izzy Carson, Power Resources Manager

SUBJECT: **2022 Power Source Disclosure Annual Report and Power Content Label**

DATE: September 20, 2023

Recommendation

Adopt a Resolution to accept and attest to the veracity of the 2022 Power Source Disclosure Program Annual Report (PSDR) and the 2022 Power Content Label (PCL).

Background and Discussion

Background

The California State Legislature passed Senate Bill (SB) 1305 in 1997, establishing the Power Source Disclosure Program in order to provide retail electricity consumers "accurate, reliable, and simple to understand information on the sources of energy that are used to provide electric services." Assembly Bill (AB) 162, adopted in 2009, modified the reporting requirements of SB 1305. AB 162 requires all retail suppliers of electricity in California (CA) to disclose the sources of the electricity they sell to customers using reporting formats developed by the California Energy Commission (CEC). In 2016, AB 1110 was passed which further modified the PSDR reporting requirements, including among other things, changes to reporting for unbundled Renewable Energy Credits (RECs) and requiring retail sellers to disclose the greenhouse gas (GHG) emissions factor associated with each electricity portfolio. The CEC updated the regulations implementing SB 1305, AB 162, and AB 1100 effective May 2020.

For each year's filing, East Bay Community Energy (EBCE) is required to 1) submit an Annual Report (the PSDR) to the CEC detailing its actual resource mix for the previous calendar year, and 2) provide an annual PCL to customers and the CEC showing the percentage breakdown by resource type. For 2022, the PCL must be posted online by October 2nd and mailed to customers by the end of 2023.

Under the CEC's regulations, private retail electricity suppliers must engage an auditor to verify the accuracy and completeness of data submitted to the CEC in the PSDR; however, public agencies are allowed to provide a self-attestation. Therefore, to fulfill its Power Source Disclosure Program reporting obligations for 2022, EBCE must provide the CEC with the Board's attestation to the veracity of the PSDR and PCL.

Power Source Disclosure Report and Power Content Label

Each year EBCE reports electricity purchases and retail sales to the CEC through the PSDR. The PSDR contains a breakdown of energy purchases over a calendar year for each retail plan and is counted as a percent of total sales by source. The CEC uses these reports from each electricity retail seller serving load in CA to generate a total CA system power mix by source.

In addition, EBCE discloses to its customers the power mix for each retail plan alongside the CA power mix on the PCL. The PCL allows customers to compare their power content to the total California power mix and to other electricity providers and is provided to customers through a mailer and posted on the EBCE webpage.

Table 1: EBCE's 2022 Power Content Label data

2022 POWER CONTENT LABEL				
Energy Resources	Renewable 100	Brilliant 100	Bright Choice	2022 CA Power Mix
Eligible Renewable	100.0%	35.8%	49.4%	35.8%
Biomass & Biowaste	0.0%	0.0%	1.5%	2.1%
Geothermal	0.0%	0.0%	0.8%	4.7%
Eligible Hydroelectric	0.0%	0.0%	1.4%	1.1%
Solar	50.0%	17.9%	18.1%	17.0%
Wind	50.0%	17.9%	27.6%	10.8%
Coal	0.0%	0.0%	0.0%	2.1%
Large Hydroelectric	0.0%	64.2%	21.9%	9.2%
Natural Gas	0.0%	0.0%	0.0%	36.4%
Nuclear	0.0%	0.0%	0.2%	9.2%
Other	0.0%	0.0%	0.0%	0.1%
Unspecified Sources of Power	0.0%	0.0%	28.4%	7.1%
TOTAL	100.0%	100.0%	100.0%	100.0%

Greenhouse Gas Emissions

AB 1110 and the CEC's regulations require electricity suppliers to disclose the GHG emissions intensity associated with its electricity sources for the previous calendar year. The GHG emissions factor can only be reported through the PCL and not on any third-party platform.

In addition to asking the Board to accept the 2022 PSDR and PCL, this report presents the emissions factor for Bright Choice from 2022 that also appears on the PCL.

EBCE 2022 Bright Choice Emissions Factor:
496 lb-CO^2e/MWh

Under EBCE's current retail plan design, the Renewable 100 product is emissions free. The Brilliant 100 product, while no longer offered, is also emissions free. The emissions from Bright Choice will decrease over time as we move towards carbon free content by 2030.

Methodology

In preparing the PSDR, staff populates the template with electricity purchases from generation that occurred during the calendar year. Delivered RECs are tracked using the Western Renewable Energy Generation Information System (WREGIS), and carbon free purchases including electricity from Large Hydroelectric generation is tracked using either meter data or E-tags. The E-tags trace the generation from the source to the delivery location. All the purchased generation is compared against invoices for accuracy, and retail sales are counted using the settlement quality meter data from our accounting service which is EBCE's system of record for sales. The complete PSDR is then reviewed internally to ensure accuracy in reporting prior to submission to the CEC.

Fiscal Impact

There are no fiscal impacts in accepting and attesting to the veracity of the 2022 Power Source Disclosure Annual Report and the 2022 Power Content Label.

Attachments

A. Resolution of the Board of Directors of East Bay Community Energy Accepting and Attesting to the 2022 Power Source Disclosure Annual Report and the 2022 Power Content Label
B. 2022 Power Source Disclosure Reports - Schedule 3
C. 2022 Power Content Label
D. Presentation of Power Source Disclosure Report and Power Content Label

RESOLUTION NO. R-2023-xx

A RESOLUTION OF THE BOARD OF DIRECTORS

OF THE EAST BAY COMMUNITY ENERGY AUTHORITY TO ACCEPT AND ATTEST TO THE VERACITY OF THE 2022 POWER SOURCE DISCLOSURE PROGRAM ANNUAL REPORT AND THE 2022 POWER CONTENT LABEL__

WHEREAS The East Bay Community Energy Authority ("EBCE") was formed as a community choice aggregation agency ("CCA") on December 1, 2016, Under the Joint Exercise of Power Act, California Government Code sections 6500 *et seq.*, among the County of Alameda, and the Cities of Albany, Berkeley, Dublin, Emeryville, Fremont, Hayward, Livermore, Piedmont, Oakland, San Leandro, and Union City to study, promote, develop, conduct, operate, and manage energy-related climate change programs in all of the member jurisdictions. The cities of Newark and Pleasanton, located in Alameda County, along with the City of Tracy, located in San Joaquin County, were added as members of EBCE and parties to the JPA in March of 2020. The city of Stockton, located in San Joaquin County was added as a member of EBCE and party to the JPA in September of 2022;

WHEREAS The California State Legislature passed Senate Bill (SB) 1305 in 1997, and in 2009 passed Assembly Bill (AB) 162, which modified the reporting requirements of SB 1305. AB 162 requires all retail suppliers of electricity in California to disclose the sources of the electricity they sell to customers using reporting formats developed by the California Energy Commission;

WHEREAS In 2016, AB 1110 was passed which further modified the Power Source Disclosure Reporting requirements; and

WHEREAS California Code of Regulations, title 20, section 1394.2(a)(2), as modified by the California Energy Commission in May 2020, allows the Board of Directors of a retail supplier of electricity that is a public agency to attest to the veracity of the information contained in the Power Source Disclosure Annual Report and Power Content Label to fulfill the audit requirement for each retail product.

NOW, THEREFORE, THE BOARD OF DIRECTORS OF THE EAST BAY COMMUNITY ENERGY AUTHORITY DOES HEREBY RESOLVE AS FOLLOWS:

Section 1. The Board of Directors accepts and attests to the veracity of the 2022 Power Source Disclosure Annual Report and the 2022 Power Content Label.

ADOPTED AND APPROVED this 20th day of September 2023.

Elisa Márquez, Chair

ATTEST:

Adrian Bankhead, Clerk of the Board

2022 POWER SOURCE DISCLOSURE ANNUAL REPORT
SCHEDULE 3: POWER CONTENT LABEL DATA
For the Year Ending December 31, 2022
East Bay Community Energy
Bright Choice

Instructions: No data input is needed on this schedule. Retail suppliers should use these auto-populated calculations to fill out their Power Content Labels.

	Adjusted Net Procured (MWh)	Percent of Total Retail Sales
Renewable Procurements	2,509,876	49.4%
Biomass & Biowaste	75,978	1.5%
Geothermal	41,346	0.8%
Eligible Hydroelectric	72,490	1.4%
Solar	917,803	18.1%
Wind	1,402,259	27.6%
Coal	-	0.0%
Large Hydroelectric	1,113,227	21.9%
Natural gas	-	0.0%
Nuclear	10,805	0.2%
Other	451	0.0%
Unspecified Power	1,441,784	28.4%
Total	**5,076,143**	**100.0%**

Total Retail Sales (MWh)	**5,076,143**
GHG Emissions Intensity (converted to lbs CO_2e/MWh)	**496**
Percentage of Retail Sales Covered by Retired Unbundled RECs	**0.6%**

2022 POWER SOURCE DISCLOSURE ANNUAL REPORT
SCHEDULE 3: POWER CONTENT LABEL DATA
For the Year Ending December 31, 2022
East Bay Community Energy
Brilliant 100

Instructions: No data input is needed on this schedule. Retail suppliers should use these auto-populated calculations to fill out their Power Content Labels.

	Adjusted Net Procured (MWh)	Percent of Total Retail Sales
Renewable Procurements	12,400	35.8%
Biomass & Biowaste	-	0.0%
Geothermal	-	0.0%
Eligible Hydroelectric	-	0.0%
Solar	6,200	17.9%
Wind	6,200	17.9%
Coal	-	0.0%
Large Hydroelectric	22,238	64.2%
Natural gas	-	0.0%
Nuclear	-	0.0%
Other	-	0.0%
Unspecified Power	-	0.0%
Total	**34,638**	**100.0%**

Total Retail Sales (MWh)	**34,638**
GHG Emissions Intensity (converted to lbs CO_2e/MWh)	**-**
Percentage of Retail Sales Covered by Retired Unbundled RECs	**0.0%**

2022 POWER SOURCE DISCLOSURE ANNUAL REPORT
SCHEDULE 3: POWER CONTENT LABEL DATA
For the Year Ending December 31, 2022
East Bay Community Energy
Renewable 100

Instructions: No data input is needed on this schedule. Retail suppliers should use these auto-populated calculations to fill out their Power Content Labels.

	Adjusted Net Procured (MWh)	Percent of Total Retail Sales
Renewable Procurements	1,421,427	100.0%
Biomass & Biowaste	-	0.0%
Geothermal	-	0.0%
Eligible Hydroelectric	-	0.0%
Solar	710,713	50.0%
Wind	710,714	50.0%
Coal	-	0.0%
Large Hydroelectric	-	0.0%
Natural gas	-	0.0%
Nuclear	-	0.0%
Other	-	0.0%
Unspecified Power	-	0.0%
Total	**1,421,427**	**100.0%**

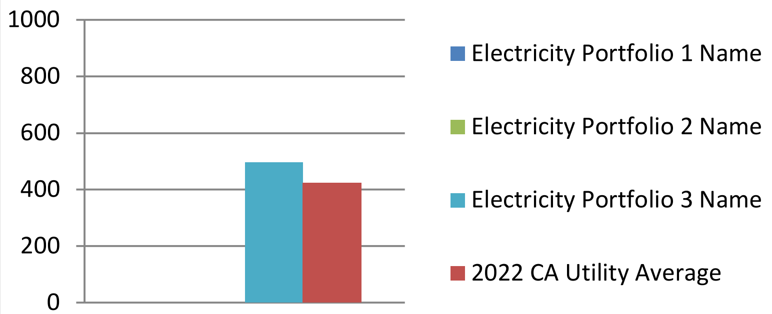
Total Retail Sales (MWh)	**1,421,427**
GHG Emissions Intensity (converted to lbs CO_2e/MWh)	**-**
Percentage of Retail Sales Covered by Retired Unbundled RECs	**0.0%**

2022 POWER CONTENT LABEL

East Bay Community Energy

https://ebce.org/key-documents/

Greenhouse Gas Emissions Intensity (lbs CO_2e/MWh)			
Electricity Portfolio 1 Name	Electricity Portfolio 2 Name	Electricity Portfolio 3 Name	2022 CA Utility Average
0	**0**	**496**	**422**



Energy Resources	Renewable 100	Brilliant 100	Bright Choice	2022 CA Power Mix
Eligible Renewable[1]	**100.0%**	**35.8%**	**49.4%**	**35.8%**
Biomass & Biowaste	0.0%	0.0%	1.5%	2.1%
Geothermal	0.0%	0.0%	0.8%	4.7%
Eligible Hydroelectric	0.0%	0.0%	1.4%	1.1%
Solar	50.0%	17.9%	18.1%	17.0%
Wind	50.0%	17.9%	27.6%	10.8%
Coal	**0.0%**	**0.0%**	**0.0%**	**2.1%**
Large Hydroelectric	**0.0%**	**64.2%**	**21.9%**	**9.2%**
Natural Gas	**0.0%**	**0.0%**	**0.0%**	**36.4%**
Nuclear	**0.0%**	**0.0%**	**0.2%**	**9.2%**
Other	**0.0%**	**0.0%**	**0.0%**	**0.1%**
Unspecified Power[2]	**0.0%**	**0.0%**	**28.4%**	**7.1%**
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**
Percentage of Retail Sales Covered by Retired Unbundled RECs[3]:	**0%**	**0%**	**1%**	

[1]The eligible renewable percentage above does not reflect RPS compliance, which is determined using a different methodology.

[2]Unspecified power is electricity that has been purchased through open market transactions and is not traceable to a specific generation source.

[3]Renewable energy credits (RECs) are tracking instruments issued for renewable generation. Unbundled renewable energy credits (RECs) represent renewable generation that was not delivered to serve retail sales. Unbundled RECs are not reflected in the power mix or GHG emissions intensities above.

For specific information about this electricity portfolio, contact:	**East Bay Community Energy** **1-833-699-EBCE (3223)**
For general information about the Power Content Label, visit:	https://www.energy.ca.gov/programs-and-topics/programs/power-source-disclosure-program

Attachment Staff Report Item 13D

SEPTEMBER 21, 2023

2022 Power Source Disclosure Annual Report and Power Content Label

EAST BAY COMMUNITY ENERGY

Overview

- What is the Power Source Disclosure Program
- How is the Power Source Disclosure Report (PSDR) prepared
- What is the Power Content Label (PCL)
- 2022 Power Content

Power Source Disclosure Program

- All electricity providers in CA are required to submit annual report
- The annual report discloses all electricity purchases for a calendar year
- Reported as MWh by source as a percent of total retail sales
- Submitted to the California Energy Commission annually

EAST BAY COMMUNITY ENERGY

PSDR Preparation

Review CY Data

- RECs
- Carbon Free
- Retail sales by plan

Data Verification

- WREGIS
- Meter Data, E-Tags
- Invoices
- Contracts

Populate PSDR Templates

- Input by generation source
- Purchased MWh as % of sales
- Individual templates for each plan

Internal Review

- Content Check
- Executive and Marketing review

Submission

- Submit to the CEC

EAST BAY COMMUNITY ENERGY

Power Content Label

- Required annual disclosure to customers, sent by mail
- Contains the power mix for each retail plan and the total CA system power mix
- Allows customers to compare their power content to the total CA power mix and to other electricity providers
- Discloses Emissions from retail plans
- The PCL will be posted online by 10/1 and mailed to customers by the end of 2023

EAST BAY COMMUNITY ENERGY

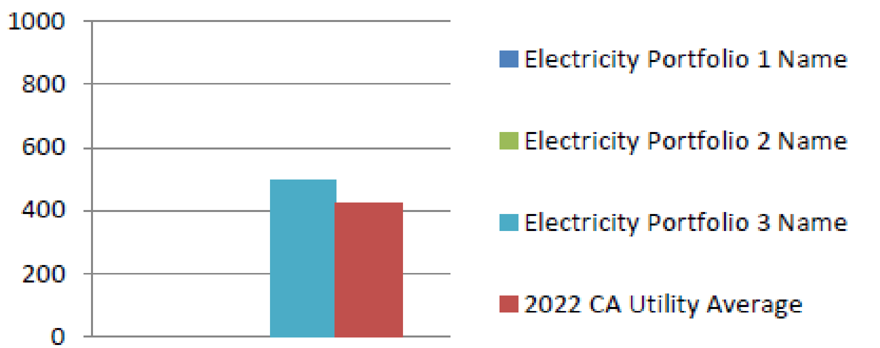
2022 Power Content Label

2022 POWER CONTENT LABEL

East Bay Community Energy

https://ebce.org/key-documents/

Greenhouse Gas Emissions Intensity ($lbs\ CO_2e/MWh$)			
Electricity Portfolio 1 Name	Electricity Portfolio 2 Name	Electricity Portfolio 3 Name	2022 CA Utility Average
0	0	496	422



Energy Resources	Renewable 100	Brilliant 100	Bright Choice	2022 CA Power Mix
Eligible Renewable[1]	100.0%	35.8%	49.4%	35.8%
Biomass & Biowaste	0.0%	0.0%	1.5%	2.1%
Geothermal	0.0%	0.0%	0.8%	4.7%
Eligible Hydroelectric	0.0%	0.0%	1.4%	1.1%
Solar	50.0%	17.9%	18.1%	17.0%
Wind	50.0%	17.9%	27.6%	10.8%
Coal	0.0%	0.0%	0.0%	2.1%
Large Hydroelectric	0.0%	64.2%	21.9%	9.2%
Natural Gas	0.0%	0.0%	0.0%	36.4%
Nuclear	0.0%	0.0%	0.2%	9.2%
Other	0.0%	0.0%	0.0%	0.1%
Unspecified Power[2]	0.0%	0.0%	28.4%	7.1%
TOTAL	100.0%	100.0%	100.0%	100.0%
Percentage of Retail Sales Covered by Retired Unbundled RECs[3]**:**	0%	0%	1%	

[1]The eligible renewable percentage above does not reflect RPS compliance, which is determined using a different methodology.

[2]Unspecified power is electricity that has been purchased through open market transactions and is not traceable to a specific generation source.

[3]Renewable energy credits (RECs) are tracking instruments issued for renewable generation. Unbundled renewable energy credits (RECs) represent renewable generation that was not delivered to serve retail sales. Unbundled RECs are not reflected in the power mix or GHG emissions intensities above.

For specific information about this electricity portfolio, contact:	**East Bay Community Energy** **1-833-699-EBCE (3223)**
For general information about the Power Content Label, visit:	https://www.energy.ca.gov/programs-and-topics/programs/power-source-disclosure-program

EAST BAY COMMUNITY ENERGY

Questions?

Thank You

Izzy Carson

Power Resources Manager

EAST BAY COMMUNITY ENERGY

CAC Item C6
Staff Report Item 15

TO: East Bay Community Energy Board of Directors

FROM: Alex DiGiorgio, Public Engagement Manager

SUBJECT: **Community Advisory Committee (CAC) structure (Discussion Item)**

DATE: September 20, 2023

Recommendation
Receive staff report on Community Advisory Committee (CAC) structure and provide direction regarding how to restructure the Committee (if at all) in light of EBCE's expanding service area and inclusion of new member-jurisdictions to the Joint Powers Authority (JPA).

Background and Discussion
On October 21, 2020, the Board of Directors approved updates to the CAC Guide and Appointment process. These updates were made to provide proper representation and engagement of the CAC, particularly given the inclusion of EBCE's new communities in the cities of Newark, Pleasanton, and Tracy. The updates included the following: The addition of three seats (increasing the CAC to twelve active seats corresponding with the concept of "voting shares" in the JPA Agreement); configuring the apportionment of CAC seats to EBCE Service Area Regions; appointing one Alternate for each EBCE Service Area Region, for a total of five; and engaging the Mayors' Conference to appoint two at-large Members.

Since that time, the CAC has been composed of twelve active seats (Members) and five alternate seats (Alternates).

On June 21, 2023, the Board of Directors approved a six month term extension for all current CAC Members and an interim seat for the City of Stockton. The purpose for this action was to provide staff with time to help the Board consider alternative committee structures to address the challenge of shifting seat allocations created by the addition of new jurisdictions to EBCE's JPA territory.

Under the CAC's current structure, seats are distributed regionally across EBCE's service area in Alameda and San Joaquin counties.[1] Each region is allocated its number of seats according to its approximate cumulative electricity load. This corresponds to the JPA's allocation of Voting Shares votes among the Board of Directors (per JPA *Sec. 4.12.2* and *Exhibit C*).

The CAC currently has eleven members serving. One Member seat in the South Service Area Region is vacant, as are all five Alternate seats. Below is a table with the current structure, seat allocation, and membership of the CAC:

EBCE Service Area Region	Current CAC Seat Allocation	Current Alternate Seat Allocation
NORTH Albany, Berkeley, Oakland, Emeryville, and Piedmont	**3** - Anne Olivia Eldred, Chair - Cynthia Landry - Lisa Hu	Open
EAST Dublin, Livermore, and Pleasanton	**1** - Joel Liu	Open
SOUTH Fremont, Union City, and Newark	**3** - Shiva Swaminathan - Vijay Lakshman - [Open]	Open
CENTRAL Hayward, San Leandro, and Alameda County Unincorporated	**2** - Ernie Pacheco - Lorraine Souza	Open
SAN JOAQUIN COUNTY Tracy	**1** - Harman Ratia	Open
STOCKTON (interim)	**1** (TBD)	N/A
At-Large	Ed Hernandez	N/A
At-Large	Jim Lutz	N/A

<u>Issue</u>: As the CAC is currently structured, the allocation of each Service Area Region's seats adjusts to reflect the change in the JPA Voting Shares vote each time EBCE's territory expands to include new communities. In effect, whenever

[1]The one exception is the Board's recent creation of the interim seat for the City of Stockton (referenced above) at the June 21, 2023, meeting.

EBCE welcomes a new jurisdiction into its territory, one CAC Service Area Region may gain a seat on the Committee, while another loses one.

Under this arrangement, with the addition of the City of Stockton to EBCE's service area, the CAC's San Joaquin Service Area Region would gain a seat, while the CAC's South Service Area Region (which includes the cities of Fremont, Newark, and Union City) would lose one. This dynamic is illustrated in the tables below.

CAC's regional seat allocation *before* Stockton's JPA membership:

Region	Member Jurisdictions	New JPA Vote Share	CAC Seat Allocation	Alternate Seat Allocation
North	Albany, Berkeley, Oakland, Emeryville, Piedmont	30%	3	1
East	Dublin, Livermore, Pleasanton	14%	1	1
South	Fremont, Union City, Newark	27%	3	1
Central	Hayward, San Leandro, Unincorporated AlCo	23%	2	1
San Joaquin County	Tracy	6%	1	1
At-Large	All		1	
At-Large	All		1	
		100%	12	5

CAC's regional seat allocation *after* Stockton's JPA membership:

Region	Member Jurisdictions	New JPA Vote Share	CAC Seat Allocation	Alternate Seat Allocation
North	Albany, Berkeley, Oakland, Emeryville, Piedmont	27.6%	3	1
East	Dublin, Livermore, Pleasanton	12.8%	1	1
South	Fremont, Union City, Newark	19.6%	2	1
Central	Hayward, San Leandro, Unincorporated AlCo	18.7%	2	1

San Joaquin County	Tracy, Stockton	21.3%	2	1
At-Large	All		1	
At-Large	All		1	
		100%	12	5

Alternative Committee Structures

As referenced above, the CAC's current, regionally-determined seat allocations reflect the approximate combined Voting Shares percentages of each JPA member-jurisdiction outlined in Exhibit C of the JPA Agreement. Under this Committee structure, the prospect of one region losing a seat if/when EBCE welcomes new jurisdictions to its JPA and service area will persist. For this reason, staff is seeking guidance from the Board regarding 1) whether to consider alternative committee structures/seat allocation mechanisms; and 2) if so, which alternatives to consider.

To assist with this, staff has summarized the strcutures of similar committees at other community choice aggregation (CCA) agencies in California. This summary is as follows:

CCA	Committee structure/ seat allocation
Central Coast Clean Energy	All At-large
Clean Energy Alliance	Jurisdiction
Clean Power Alliance	Region
Desert Clean Energy	All At-large
EBCE	Region
Orange County Power Authority	Jurisdiction
Peninsula Clean Energy	All At-large
Redwood Coast Energy Authority	Jurisdiction
San Diego Community Power	Jurisdiction
Sonoma Clean Power	All At-large
Valley Clean Energy	Jurisdiction

As outlined above, seat allocations of community advisory committees at other California-based CCAs are generally structured in one of the following three ways:

1. By region
2. By jurisdiction
3. All at-large

Each of these structures offers various potential benefits and trade-offs regarding the committee's representation and operation. These generally include the following:

Structure	Potential benefits	Potential trade offs
By Region	• Geographically distributed representation; • Proportional representation relative to population size; • Smaller committee size	• Seat allocations likely to shift as service area/JPA membership grows; • Some jurisdictions may not have individual representation; • Member appointments administered by CCA staff/Board members
By Jurisdiction	• Geographically distributed representation (+ all jurisdictions have individual representation); • Committee structure mirror's Board structure; • Member appointments administered by city/County staff	• Larger committee/more members; • No proportional representation relative to population size; • Increased fiscal impact (e.g., more stipends to be paid)
All At-large	• Smaller committee size; • Proportional representation relative to population size more likely; • Multiple members from the same region/jurisdiction can serve on the Committee	• Geographically distributed representation less likely; • Member appointments administered by EBCE staff/Board; • Potentially more challenging to reach cross-section of community members

Board Engagement

To help facilitate robust input from EBCE's Board of Directors on this subject, staff convened an Ad Hoc committee of the Board to provide initial guidance. Board members from four of the five CAC Service Area Regions participated on this committee, including the following:

- Alameda County Supervisor/EBCE Board Chair Elisa Márquez (Central)
- Dublin City Councilmember Sherry Hu (East)
- Newark City Councilmember Matthew Jorgens (South)
- Piedmont City Councilmember Betsy Andersen (North)
- Union City City Councilmember Jaime Patiño (South)

Staff also reached out to individually consult with the following:

- Current CAC Chair (Anne Olivia Eldred);
- EBCE's Vice Chair of the Board (Pleasanton Vice Mayor Jack Balch);
- The Board Members of EBCE's two largest JPA member-jurisdictions (Oakland Councilmember Dan Kalb and Fremont Councilmember Teresa Cox);
- Emeryville's EBCE Board Member (Mayor John Bauters)
- Founding EBCE Board Chair, former Alameda County Supervisor Scott Haggerty

Committee Recommendation

An Ad Hoc committee of the Board convened on August 30, 2023, to discuss the CAC's structure and offer feedback to staff and the Board. Staff also individually conferred with three Board members. The bullets below summarize the key points that came out of these conversations:

- While Ad Hoc committee members acknowledged the appeal of a jurisdictional structure (i.e., one that mirrors the Board), they expressed concerns regarding 1) increasing the size of the CAC; 2) filling the seats/finding interested community members in each jurisdiction; and 3) coordinating with cities regarding the appointment timing and process;
- Given these concerns, the consensus of the Ad Hoc committee and the Board members with whom staff individually consulted was to maintain the CAC's regional structure;
- There was support expressed for either 1) removing the two At-Large CAC seats; or 2) exploring how to reallocate the seats to the Service Area Regions, since the At Large seats invite an imbalance among the regions/jurisdictions (e.g., Oakland gains an additional seat). Staff also noted the current At Large appointment process through the Alameda County Mayors' Conference does not align well with the timing of CAC terms/operations.
- The Board should consider removing the Alternate seats, since filling them has proven difficult (they are all currently vacant);
- The Board should consider instructing staff to stagger the terms of the current CAC members so that half of the members' terms end in an even year, and the other half in an odd year, with terms beginning in June with the fiscal calendar.
- The Board should consider allowing current CAC members who wish to continue serving to do so without having to reapply;

Based on communications with the CAC Chair, staff anticipates the CAC will discuss the Committee's structure at its meeting on September 19, 2023. The CAC may provide its own feedback and recommendations to the Board thereafter.

Fiscal Impact

There is no fiscal impact to considering alternative CAC structures. If EBCE's Board votes to restructure the CAC this could affect the amount of money budgeted for Committee member stipends. The current CAC stipend budget is $20,400. If the committee were to be restructured to have fewer seats, the budget would decrease proportionally. Alternatively, if the Committee were to be restructured to mirror the Board (i.e., one seat allocated to each jurisdiction) this would require an additional four seats, increasing the stipend budget to approximately $27,200. The additional stipends would be disbursed as new CAC members are sworn-in and begin serving at regular, monthly meetings.

Attachments

A. CAC Structure Ad Hoc PPT – 8.30.23

Attachment Staff Report Item 15A

AUGUST 30, 2023

Ad Hoc Committee: Community Advisory Committee (CAC) Structure

EAST BAY COMMUNITY ENERGY

Objective: To address the issue of shifting CAC seat allocations

- ## Issue:

  The current regional structure of the CAC results in one region potentially losing an allocated seat when a new jurisdiction joins the JPA

  - E.g., Stockton joining JPA = CAC's San Joaquin region gains a seat, while the CAC's South region (Fremont, Newark, Union City) loses a seat

- ## Ad Hoc Committee Assignment:

1. **To advise staff and EBCE Board of Directors re how to restructure the CAC (if at all) as EBCE grows to include new jurisdictions**
2. **To consider various committee structures for the CAC**
   - e.g., Regional vs. Jurisdictional vs. At-Large

EAST BAY COMMUNITY ENERGY

CAC Intro

Overview

- The CAC is a Brown Act body established in EBCE's JPA
- The CAC meets monthly on the Monday before the Board of Directors mtg
- To Join: Interested members of the public submit applications for open seats; Board Members for each region make nominations from among the applicants; final appointments are approved by the full Board.
- At-large Members are appointed by the Alameda County Mayor's Conference
- Members can serve 2-year terms for a maximum of 4 terms (8 years total)

Current Structure

Region	Member Jurisdictions	JPA Vote Share	CAC Seat Allocation	Alternate Seat Allocation
North	Albany, Berkeley, Oakland, Emeryville, Piedmont	30%	3	1
East	Dublin, Livermore, Pleasanton	14%	1	1
South	Fremont, Union City, Newark	27%	3	1
Central	Hayward, San Leandro, Unincorporated AlCo	23%	2	1
San Joaquin County	Tracy	6%	1	1
At-Large	All		1	
At-Large	All		1	

**City of Stockton: Interim seat awaiting appointment*

Current CAC Membership

Attachment Staff Report Item 15A

NAME	REGION	CITY OF RESIDENCE
Anne Olivia Eldred, Chair	North	Oakland
Cynthia Landry	North	Oakland
Jim Lutz	At Large	Oakland
Lisa Hu	North	Oakland
Joel Liu	East	Pleasanton
Shiva Swaminathan	South	Fremont
Vijay Lakshman	South	Fremont
Lorraine Souza	Central	Hayward
Ernesto Pacheco	Central	Hayward
Ed Hernandez,Vice Chair	At Large	San Leandro
Harman Ratia	San Joaquin	Tracy

Current Vacancies:

- All five Alternate seats
- South Region Member
- Stockton Interim Member

EAST BAY COMMUNITY ENERGY

Ad Hoc Committee Background

Why are we here?

- With the addition of Stockton (and possible further expansion) the Board may wish to consider structural changes to avoid having some CAC regions lose seats while others gain them.

- Most of the CCA's in California that have CACs have one of the following structures:

  - **Regional**: The service area is divided into regions and CAC seats are allocated on a per region basis. This is EBCE's current structure.
  - **Jurisdictional**: Seats are allocated to each JPA member-jurisdiction on a per city/county basis, often mirroring the BOD structure.
  - **At-large**: Seats are not allocated to any specific regions/jurisdictions.

- Additional structural questions to consider:

  - Alternates?
  - Terms?
  - Appointment process

CCA Comparison

Attachment Staff Report Item 15A

CCA	Committee structure/seat allocation
Central Coast Clean Energy	All At-large
Clean Energy Alliance	Jurisdictional
Clean Power Alliance	Regional
Desert Clean Energy	All At-large
EBCE	Regional
Orange County Power Authority	Jurisdictional
Peninsula Clean Energy	All At-large
Redwood Coast Energy Authority	Jurisdictional
San Diego Community Power	Jurisdictional
Sonoma Clean Power	All At-large
Valley Clean Energy	Jurisdictional

EAST BAY COMMUNITY ENERGY

Regional Approach Allocations w/ Stockton

Region	Member Jurisdictions	New JPA Vote Share	CAC Seat Allocation	Alternate Seat Allocation
North	Albany, Berkeley, Oakland, Emeryville, Piedmont	27.6%	3	1
East	Dublin, Livermore, Pleasanton	12.8%	1	1
South	Fremont, Union City, Newark	19.6%	~~3~~ 2	1
Central	Hayward, San Leandro, Unincorporated AlCo	18.7%	2	1
San Joaquin County	Tracy, **Stockton**	21.3%	~~1~~ 2	1
At-Large	All		1	
At-Large	All		1	
		100%	12	5

EAST BAY COMMUNITY ENERGY

Next Steps

- 8/30: Ad Hoc mtg to discuss future of CAC structure
- 9/6: If necessary/desired, item goes to Executive Committee
- 9/18: CAC discusses item and may provide recommendation to Board
- 9/20: Item goes before full Board of Directors for discussion/final decision

12/31/23: End of term for all current Members of the CAC

Appointment timelines by structure:

- **Regional** (current structure): Applications (Oct/Nov); Nominations (Nov); Appointment by BOD (December).
- **Jurisdictional**: Appointments by cities/County (Oct-Dec)
- **At Large**: Applications (Oct); Appointments by BOD (December)

Thank You!

Alex DiGiorgio,
Public Engagement Manager
ADiGiorgio@ebce.org

Questions? Give us a call:

1-833-699-EBCE (3223)

@PoweredbyEBCE

customer-support@ebce.org

Español
ebce.org/es

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EAST BAY COMMUNITY ENERGY

CAC Item C7

Staff Report Item 14

TO: East Bay Community Energy Board of Directors

FROM: Kelly Brezovec, Director, Account Services

Contributors: Jin Ruan, Energy Analyst - Financial Modeler
Shannon Rivers, Virtual Power Plant Manager
Feliz Ventura, Resilience Programs Manager
Doug Allen, Modeler-in-Chief
Michael Quiroz, Sr Regulatory Analyst

SUBJECT: Informational Discussion on the Net Billing Tariff as a Successor to the Net Energy Metering 2.0 Tariff

DATE: September 20, 2023

Recommendation

Receive an update on staff plans to address the Net Billing Tariff (NBT) as a successor to Net Energy Metering (NEM) 2.0.

Background

EBCE regulatory staff has been tracking the NEM 2.0 successor tariff, and presented on major developments at the December 2022 Board of Directors meeting. At that time the Commission had not yet finalized their decision. Since then, the Net Billing Tariff was approved on December 15, 2022.

In 1995, the first Net Energy Metering tariff was established through the passage of SB 656. NEM 1.0 was a tariff favorable to mid-day solar production, such that customers were compensated for generating solar in excess of what they consumed. NEM 1.0 is responsible for starting the annual credit cycle and true-up process, which serves as a mechanism to compensate customers for their solar generation. On a monthly interval, credits are provided to customers at the retail rate that can be used to offset energy usage. Annually, at an event called the “true-up,” the customer is paid out at the Net Surplus Compensation (NSC) rate, which is similar to a market-based rate, for excess solar generation. The customer’s NEM credits then reset and they start again for another 12 month cycle. Customers were granted a

20 year interconnection agreement and a guaranteed 20 years on this tariff, which was available through 2017.

NEM 2.0, the successor to NEM 1.0, is very similar to NEM 1.0, but requires a time-of-use (TOU) rate for all NEM customers where rates differ depending on the time of day. Lower retail rates are mid-day in response to the glut of solar on the grid and higher rates are charged in the late afternoon and early evening when demand peaks and solar production wanes. Usage and generation are netted based on the TOU period. NEM 2.0 customers are also responsible for non-bypassable charges, such as the Public Purpose Programs charge. Annual payouts are provided at NSC rates. Customers on this tariff were given 20 years to remain on NEM 2.0, with the legacy period remaining with the solar system itself. NEM 2.0 was offered to solar systems with applications received from 2017 through April 14, 2023. We can expect NEM 2.0 customers to transition to NBT starting in 2037.

Net Billing Tariff (NBT) is the successor to NEM 2.0. Rather than receive the retail rate for generation that is exported to the grid, customers receive compensation at a new Avoided Cost Calculation (ACC) rate, also called the Energy Export Credit. The ACC is a tool used by the California Public Utility Commission (CPUC) to determine the value of onsite solar and other distributed energy resources.The ACC varies by the hour and the month. Spring and summer mid-day ACC prices are the lowest while late summer early evening prices are the highest. ACC pricing is aligned with historic California Independent System Operator, or CAISO, energy demand and availability. There is a “glidepath” for new NBT customers, which provides a small adder, or increase, to the established ACC rates to help ease the transition from NEM 2.0 to NBT.

See Table 1 for a comparison summary of NEM 1.0, NEM 2.0, and the NBT.

Click here to enter text.Table 1: Summary of NEM 1.0, NEM 2.0, and NBT

	NEM 1.0 **1996-2017**	**NEM 2.0** **2017-Apr.14, 2023**	**NBT** **Apr. 15, 2023 - present**
Rate Schedule	Any	TOU rates (4-9 pm peak rates)	Residential customers are required to be on a TOU Electrification Rates (4-9pm peak, 3pm-12am partial peak)
Value of solar used concurrently on-site	Offsets imports, equivalent to retail rate	Offsets imports, equivalent to retail rate	Offsets imports, equivalent to retail rate

Value of solar exported to grid	Full retail rate	Retail rate minus non-bypassable charges	Avoided Cost Calculation (ACC) price per hour, with an adder for low income customers.
Netting methodology	Imports are netted against exports	Imports are netted against exports within each TOU interval	Imports are charged at the retail rate, exports are compensated at ACC. Energy use is no longer netted.
Net Surplus Compensation (NSC) payment at true-up	Net exports times NSC rate	Net exports times NSC rate	Net exports times NSC rate, minus ACC export value already granted
Billing and true-up period	Annual billing, annual true-up (both charges and credits roll over for 12 months)	Annual billing, annual true-up (both charges and credits roll over for 12 months)	Monthly billing and payment; annual true-up (credits roll over for 12 months)
Legacy Period	20 Years, tied to the system	20 Years, tied to the system	9 Years, tied to both the system AND the customer as a unit.

California Public Utilities Commission Goals

The California Public Utilities Commission (CPUC) has had a different set of goals with each iteration of the Net Metering Tariff (now, Net Billing Tariff).

NEM 1.0 was developed to promote rooftop solar and diversify the energy resource mix. The tariff favored the midday peak solar production and credited customers at the full retail rate. While NEM 1.0 was successful at its goal of proliferation of rooftop solar, this is when the state started to grapple with the infamous duck curve that aligned with abundant mid-day solar.

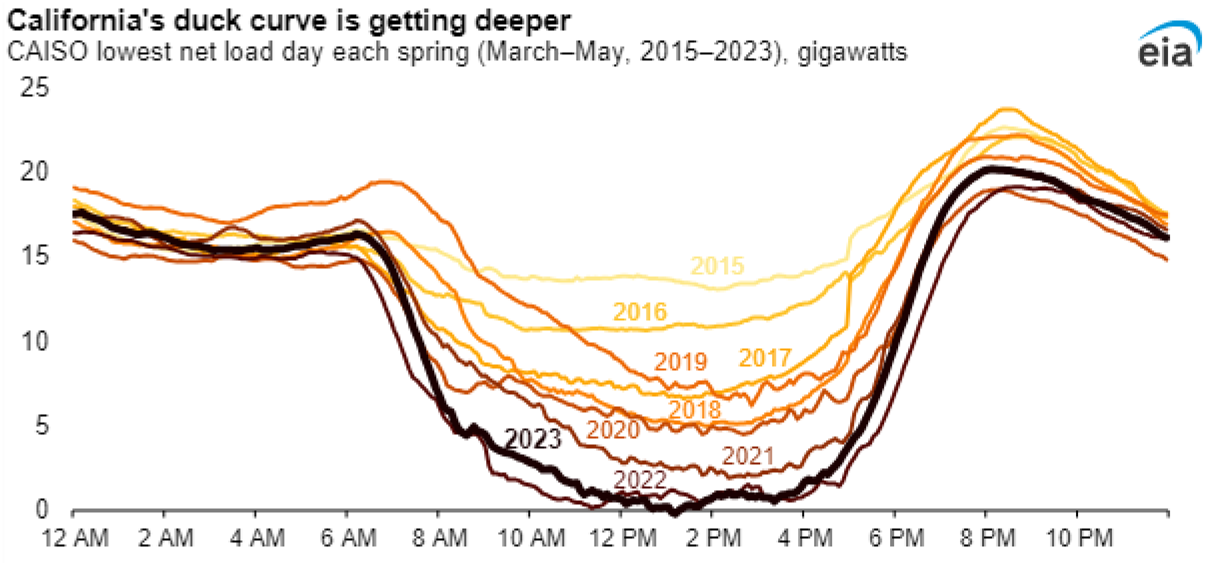

Figure 1: The Duck Curve[1]

NEM 2.0 was the CPUC's first attempt to align the compensation structure closer to costs by way of TOU rates configured to match supply. NEM 2.0 also included requirements to pay non-bypassable charges, including a minimum delivery fee.

NEM 1.0 and NEM 2.0 have shown to increase pricing to non-NEM customers by paying an artificially high price for inexpensive mid-day energy generation to NEM customers. The CPUC's study by Energy + Environmental Economics and Verdant estimates that NEM 2.0 customers annually shift about $2,600 of their energy cost burden to non-NEM customers[2] (for both generation and delivery).

NBT is designed to better align generation compensation (the ACC, or avoided cost calculation) for customer-sited solar with the actual net benefits provided to the grid. NBT's structure encourages on-site battery storage, which could help to flatten the duck curve.

Implementation Schedule

There are two groups of customers that will initially be eligible for NBT:

1. Customers that completed their self-generation application after April 14, 2023 will be automatically placed on NBT.
2. Customers that have completed 20 years on NEM 1.0 will transition to NBT at their next PG&E delivery true-up.

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[1] From *As solar capacity grows, duck curves are getting deeper in California*, June 21, 2023 from the U.S. Energy Information Administration at: https://www.eia.gov/todayinenergy/detail.php?id=56880

[2] From *Cost-effectiveness of NEM Successor Rate Proposals under Rulemaking 20-08-020*, May 28, 2021. Page 29 at: https://willdan.app.box.com/s/3jpscul3lbtof5erje7f4bkqk96uahp/file/816006172639

Given the complexities of this new tariff, PG&E's billing systems are not ready to bill on NBT, which they are calling "Solar Billing Plan," or SBP. PG&E expects to have their residential SBP operations ready by December 2023 and non-residential prepared by July 2024. Once the billing systems are ready, customers will transition to SBP based on their PG&E delivery true-up date.

Underlying Limitations and Opportunities

Price and Billing Signals
EBCE customers are also PG&E customers for delivery service. Since PG&E will be billing for delivery charges on the Solar Billing Plan tariff, customers will receive the price signals from this portion of their bill and will feel that change from NEM 2.0 to SBP. For customers installing today, they'll be basing their purchase decision on SBP models, as solar providers have historically used only PG&E pricing to model solar performance.

Data Opportunities
Considering two-way meter channel data (both imports and exports) may lead to enhanced understanding of customer usage and generation patterns, allowing for more targeted incentive opportunities. Ingesting and using hourly billing quality meter data is also a global requirement as we look to tariffs of the near future, like Day Ahead Real Time Pricing.

Customer Opportunities and Legacy Systems
Customers are not without agency in this tariff change. While NBT does not offer the retail rate for exports, energy generated and used onsite without being exported is still "worth" the retail rate. Customers can see value on the NBT rate by installing a smaller solar system to offset their "base" or "always-on" load, shifting their demand to meet their own generation supply, or adding battery storage to take advantage of higher retail rates in the late evening hours, either to offset their own energy use during peak hours, or benefitting from the higher export rates.

Customers are also allowed 20 years on NEM 2.0. EBCE will continue to offer NEM 2.0 through 2044, accounting for the legacy period of customers who are just installing their systems today and through 2024. EBCE serves 63,000 customers on NEM 1.0 and NEM 2.0 today. Based on historic installation data, staff expects to see a steady, but slow transition of customers from NEM 1.0 and 2.0 over to NBT. Over half of today's NEM customers won't transition to NBT until 2038, as shown in Figure 2.

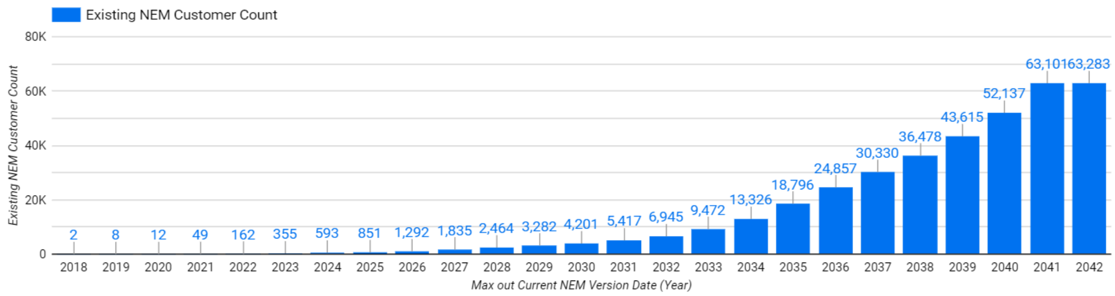


Figure 2: Charting customers transition dates, NEM 1.0 and 2.0 to NBT (EBCE data)

<u>Status</u>

Staff is exploring the impacts to both our customers and our organization of mirroring NBT as prescribed by the CPUC and largely as implemented by PG&E. Staff is using current customer usage and generation data to model ways for customers to maximize their rooftop solar system to benefit their energy bills, as well as add-ons like battery storage that can help reduce both bills and grid reliability. In the meantime, our billing agent is developing requirements to bill customers on SBP.

Today, EBCE offers a bonus credit to our low-income NEM customers and we continue to discuss equity concerns, including ways to assist in development of rooftop solar and battery storage by way of increasing the export credit. The ACC, or energy export credit, already includes an adder for low-income customers. Staff may look to increase the value or duration of this adder.

Staff is also exploring incentives for customers that use batteries per our time requirements. Battery storage and discharge at the right times helps with overall grid stability and helps reduce EBCE procurement costs, which can be passed on to all customers.

Staff expects to return to the Board no later than December 2024 with a proposal for how EBCE will implement a successor to the NEM 2.0 tariff.

<u>Fiscal Impact</u>

Staff is modeling fiscal implications of options for a successor tariff to NEM 2.0.

<u>Attachments</u>

A. Presentation

Attachment Staff Report Item 14

SEPTEMBER 20, 2023

Informational Discussion on the Net Billing Tariff as a Successor to the Net Energy Metering 2.0 Tariff

EAST BAY COMMUNITY ENERGY

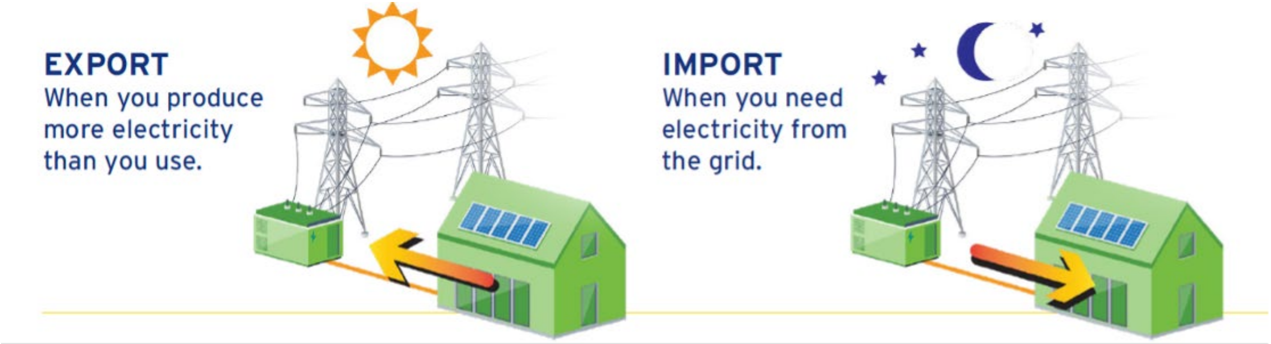
Introduction – What is Net Energy Metering?

Net Energy Metering (NEM) is the historic billing methodology used to compensate customers for excess energy produced by their own systems, like rooftop solar. NEM also defined how this compensation was handled vis-a-vis customer usage.

EAST BAY COMMUNITY ENERGY

Introduction – What is Net Billing Tariff?

Net Billing Tariff (NBT) is a new compensation tariff approved by the CPUC on December 15, 2022. Energy exports, or excess generation is "sold" back at one price and energy imports, or electricity used from the grid, is purchased at the standard customer rate.



Timeline

NEM 1.0
1996 - 2017

NEM 2.0
2017 – 4/2023

NBT
4/2023 -

EAST BAY COMMUNITY ENERGY

CPUC Goals

NEM 1.0
1996 - 2017

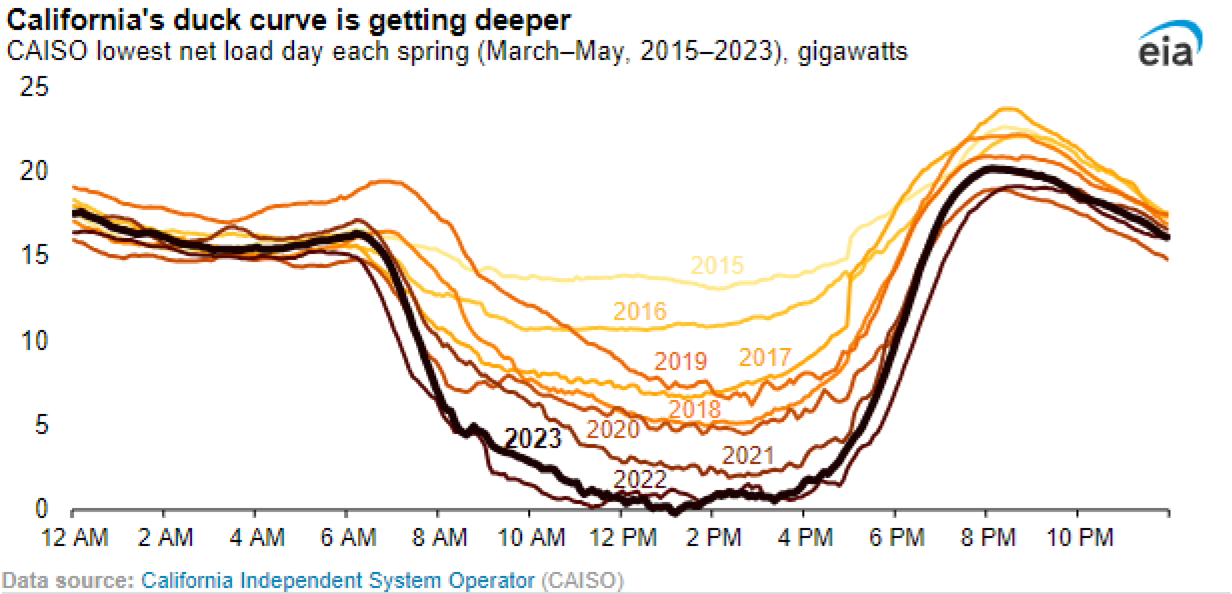
NEM 2.0
2017 – 4/2023

NBT
4/2023 -

NEM 1.0	NEM 2.0	NBT
• Promote rooftop solar • Diversify resource mix • Tariff favored mid-day solar production	• More closely align compensation closer to cost via TOU rate • Require participants to pay non-bypassable charges	

EAST BAY COMMUNITY ENERGY

The Duck Curve



CPUC Goals

NEM 1.0
1996 - 2017

NEM 2.0
2017 – 4/2023

NBT
4/2023 -

NEM 1.0	NEM 2.0	NBT
• Promote rooftop solar • Diversify resource mix • Tariff favored mid-day solar production	• More closely align compensation closer to cost via TOU rate • Require participants to pay non-bypassable charges	• Continued refinement of compensation related to net benefits to the grid • Allow for continued growth of self-generation

EAST BAY COMMUNITY ENERGY

Solar Metering Tariffs: Side-by-Side

	NEM 1.0 1996-2017	NEM 2.0 2017-Apr.14, 2023	NBT Apr. 15, 2023 - present
Rate Schedule	Any	TOU rates (4-9 pm peak rates)	Residential customers are required to be on a TOU Electrification Rates (4-9pm peak, 3pm-12am partial peak)
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Legacy Period	20 Years, tied to the system	20 Years, tied to the system	9 Years, tied to both the system AND the customer as a unit.

	NEM 1.0 1996-2017	NEM 2.0 2017-Apr.14, 2023	NBT Apr. 15, 2023 - present
Value of solar used concurrently on-site	Offsets imports, equivalent to retail rate	Offsets imports, equivalent to retail rate	Offsets imports, equivalent to retail rate
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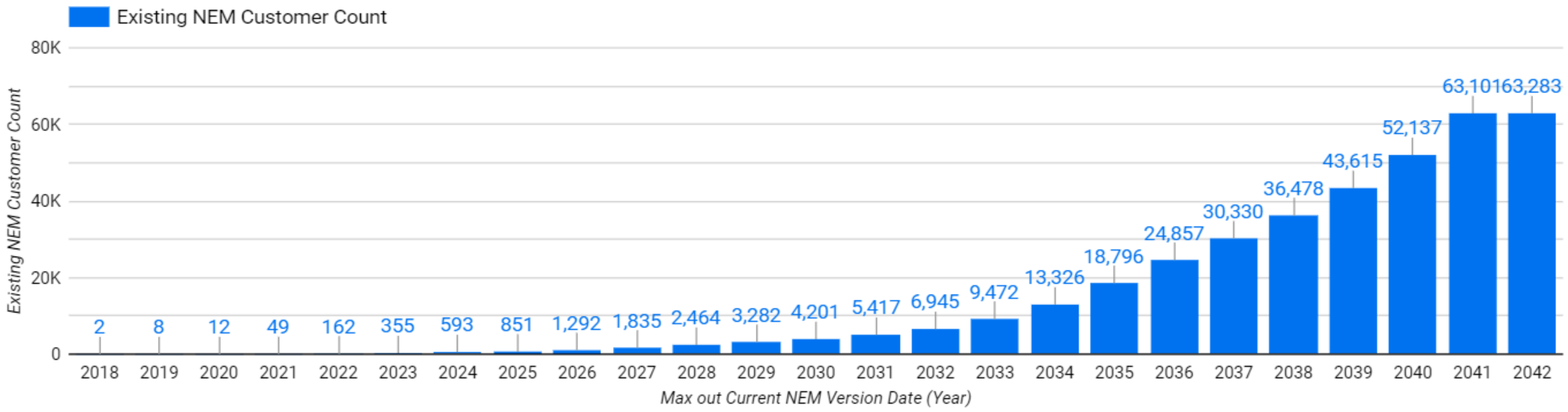
Netting methodology	Imports are netted against exports	Imports are netted against exports within each TOU interval	Imports are charged at the retail rate; exports are compensated at ACC. Energy use is no longer netted.

Customer Transitions from NEM 1 and 2 to NBT

Cumulative Customer Count Eligible for NBT



EAST BAY COMMUNITY ENERGY

Next Steps

- Staff is exploring the impacts of mirroring NBT as prescribed by the CPUC, as well as looking for opportunities to customize the tariff for our customers and agency
- Exploring questions such as:
  - How can NBT create value for our solar customers as well as our other customers?
  - How will EBCE continue to support our low-income customers?
  - Battery storage and timely discharge can help with overall grid stability. Battery storage can also help reduce customer bills and increase the value of rooftop solar. Is there an opportunity for a program to help encourage battery adoption?
- Staff expects to return to the Board no later than December 2024 with a proposal for how EBCE will implement a successor to the NEM 2.0 tariff

Thank You!

Questions? Give us a call:

1-833-699-EBCE (3223)

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customer-support@ebce.org

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EAST BAY COMMUNITY ENERGY

CAC Item C8

Staff Report Item 11

TO: East Bay Community Energy Board of Directors

FROM: Alex DiGiorgio, Public Engagement Manager

SUBJECT: **Inclusion of New Communities: City of Lathrop (Action Item)**

DATE: September 20, 2023

Recommendations

Receive staff report and analysis on including the City of Lathrop within EBCE's service area and take the following actions:

A) Adopt a Resolution to authorize the City of Lathrop to join the EBCE as a member agency and signatory to the JPA Agreement, with customer enrollments to begin in 2025, and to direct staff to update Exhibit A ("List of Parties"), Exhibit B ("Annual Energy Use"), and Exhibit C ("Voting Shares Vote") of EBCE's Joint Powers Agreement to reflect the inclusion of Lathrop.

B) Adopt a Resolution to authorize staff to update EBCE's Implementation Plan to reflect the inclusion of the City of Lathrop, and to submit the updated Implementation Plan to the California Public Utilities Commission (CPUC) before the end of calendar year 2023.

Background and Discussion

As a mission-driven public agency, EBCE strives to reduce energy-related greenhouse gas (GHG) emissions by providing access to renewable energy at competitive rates while pioneering innovative programs and policies. To the extent EBCE retains and expands its customer base, it can accelerate the achievement of this mission. Moreover, by including new communities within its service area, EBCE can cultivate a more demographically diverse customer base; and more generally advance sustainable development, environmental justice, and energy democracy throughout neighboring communities in California.

New Community Inclusion: Requirements, Timing, Process

Section 3.1 of EBCE's Joint Powers Authority (JPA) Agreement refers to the "Addition of Parties," and provides for the possibility of including new cities and/or counties within the JPA and its corresponding service area with updates to the JPA Agreement's Exhibits.

Requirements: New community inclusion process and conditions of membership

In order to join EBCE, the following legal and procedural requirements must be met: **1)** the governing body of the prospective jurisdiction (i.e., the City Council) must pass a Resolution requesting to join EBCE and agreeing to become a signatory of the EBCE JPA Agreement; and pass an ordinance to implement a community choice aggregation program pursuant to Public Utilities Code Section 366.2; **2)** EBCE's Board must pass a Resolution authorizing the addition of the prospective jurisdiction as a new member and directing staff to update the JPA Agreement Exhibits; and **3)** finally, EBCE must submit an updated Implementation Plan to the California Public Utilities Commission (CPUC) reflecting the membership of the new jurisdiction(s) within EBCE's JPA.

The Lathrop City Council has already adopted the required Resolution agreeing to become a signatory to EBCE's JPA Agreement and join EBCE; and it has passed the required two readings of a corresponding ordinance pursuant to Public Utilities Code Section 366.2 (please see attachments). The next step in Lathrop's EBCE membership process is for the EBCE Board of Directors to adopt the proposed Resolution adding Lathrop to the JPA Agreement to add the City to EBCE's membership, with customer enrollments to begin in 2025.

Section 3.1 of the JPA Agreement also provides for the satisfaction of other "additional conditions" for JPA membership, including "membership payment" or "membership fee," which are subject to the discretion of EBCE's Board. To date, the EBCE Board has not imposed such conditions on membership for new parties. Lathrop's elected leaders, City staff, and community members expect the City to be able to join EBCE's JPA and participate in its governance under the same conditions as all current members. If these expectations are not met, it could lead Lathrop and/or future, prospective new member-jurisdictions in San Joaquin County or elsewhere to become less interested in joining EBCE. For these reasons, the Board is encouraged to proceed cautiously when considering conditions on new membership.

Once Lathrop has joined EBCE and its membership is certified by the CPUC, the City will be entitled to appoint a member of the City Council to serve as a member of the EBCE Board of Directors.

Requirements: Update JPA Exhibits A, B, & C

To implement the addition of Lathrop as a signatory and member of EBCE, the Board must approve updates to JPA Exhibits A ("List of Parties"); B ("Annual Energy Use"); and C ("Voting Shares"). Section 1.3 of the JPA Agreement provides that Exhibits A, B, and C may be revised upon the approval of the Board, without such revision constituting an amendment to the Agreement.

Exhibit A: "List of Parties"

Exhibit A lists the names of all jurisdictions which are members of EBCE's Joint Powers Authority. Updating this list is straightforward; it simply involves adding the names of new member jurisdictions, pending the passage of a Board Resolution authorizing their JPA membership.

If the Board authorizes the membership of the City of Lathrop, the City's name must be added to Exhibit A listed in alphabetical order (draft Attached).

> ***Recommendation***: Pending Board authorization to include the City of Lathrop, approve a motion to update Exhibit A to include the City among the "List of Parties."

Exhibits B & C: "Annual Energy Use" & "Voting Shares Vote"

Exhibits B and C list the annual energy use and the voting shares percentage of each member jurisdiction.

The Board voting procedures are set forth in *Section 4.12* of the JPA Agreement. According to *Section 4.12.1*, most Board decisions require a simple majority vote of all the Directors, with each jurisdiction having one equal vote.[1] This procedure is referred to as a "Percentage Vote." Additionally, *Section 4.12.2* creates a "Voting Shares Vote" procedure, which may immediately follow an affirmative or a tied Percentage Vote if requested by three or more Directors. Under a Voting Shares Vote, each jurisdiction's vote is essentially 'weighted' according to the size of its annual energy usage as compared to EBCE's total annual energy (i.e., the collective, community-wide electricity demand within its borders). Historically, the Board has allowed new members to participate in 'Voting Shares' at their entry into EBCE,

[1] *Section 8.4* ("Amendment of this Agreement") requires a two-thirds majority vote to amend the JPA itself; and a three-quarters vote to amend the voting provisions of *Section 4.12*.

rather than waiting until service to the new community is launched.[2] Staff recommends the Board continue following this precedent, rather than risk alienating prospective new member-jurisdictions.

To date, the Voting Shares Vote provision of the JPA has been invoked exceedingly rarely—if ever. Indeed, no current EBCE staff member can recall an instance in which a vote of this type has occurred since EBCE's formation in 2016.

Exhibit B sets forth the Annual Energy Use for each member-jurisdiction and EBCE's Total Annual Energy use, for purposes of calculating members' voting shares.

According to *Section 1.1.23* of the JPA Agreement, "Annual Energy Use" for the first two years after EBCE's launch date (December 1, 2016) is based on the annual electricity usage within each member's respective jurisdiction. After two years, the JPA Agreement provides that Annual Energy Use is to be based on the annual electricity usage of accounts served by EBCE within the member's jurisdiction. The Total Annual Energy is the sum of all the member jurisdictions' Annual Energy Use. The numbers in Exhibit B, together with the corresponding voting shares in Exhibit C, are supposed to be "adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 each year subject to the approval of the Board."

At the time of EBCE's formation, Exhibit B relied on 2014 PG&E load data. From 2019 to 2021, Exhibit B relied on 2018 PG&E load data.[3] Since 2022, Exhibit B has relied on 2021 PG&E load data. Staff's recommendation is to continue updating Exhibit B to reflect more current load data.

Specifically, EBCE staff recommends the Board update Exhibit B using the most recent PG&E load data available (i.e., from calendar year 2022).[4] This provides an 'apples-to-apples' comparison for each member jurisdiction and does not preclude the Board from transitioning to EBCE's post-enrollment load data once a full calendar year of EBCE usage becomes available for the cities of Stockton and Lathrop.[5]

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[2] When EBCE's Board voted in 2019 to include the cities of Newark, Pleasanton, and Tracy; and the City of Stockton in 2022, it did so with the intention of allowing those new member-jurisdictions to participate in Voting Shares Votes based on their respective, citywide PG&E load data if/when such votes were to occur. Staff recommends the current EBCE Board follow this precedent.

[3] From 2019 to 2021, Exhibit B relied on 2017 PG&E load data for the City of Newark. This was due to the lengthy time required to receive Newark's requested 2018 load data from PG&E before the end of the 2019 calendar year.

[4] The most recent PG&E load data available to EBCE is from calendar year 2022 for all jurisdictions, including the City of Lathrop.

[5] The City of Stockton's EBCE enrollment was delayed until January 1st, 2025, by CPUC Resolution E-5258.

Exhibit C sets forth the Voting Shares for EBCE member jurisdictions based on the corresponding Annual Energy Use and Total Annual Energy numbers provided in Exhibit B. If the Board decides to follow staff's recommendation and provides direction to update Exhibit B using 2022 PG&E load data, Exhibit C will be adjusted accordingly to reflect the Voting Shares percentage of each member jurisdiction.

> ***Recommendation***: Update Exhibit B using 2022 PG&E load data for "Annual Energy Use" and "Total Energy Use," for all current EBCE member-jurisdictions and the City of Lathrop. Update Exhibit C's Voting Shares to correspond to updated numbers in Exhibit B. Consider updating Exhibits B and C again in 2024 using 2023 EBCE load data, when such data becomes available for EBCE member-jurisdictions.

Timing of new enrollments

In February of 2018, the CPUC passed Resolution E-4907, which delays the timeline by which California cities and counties may begin service with Community Choice Aggregation (CCA) agencies, like EBCE. In effect, cities and counties must wait a full calendar year between the time they form or join a CCA and when electricity customers within their borders may be enrolled in the CCA's service. As a result, any jurisdiction that requests to begin service with EBCE by 2025, must complete the process of joining EBCE's JPA by the end of calendar year 2023. Otherwise, enrollment with EBCE will not be possible until 2026 or later.

In April of 2023, the CPUC passed Resolution E-5258, which delayed the City of Stockton's EBCE enrollment until January 1, 2025 (as well as the enrollments of other California cities that had been preparing to join CCAs in 2024). In brief, E-5258 retroactively applied additional conditions to CCAs that were planning to expand their service to new communities. These conditions focused on the timing of Resource Adequacy ("RA") procurement and compliance requriements. EBCE has since adjusted its RA planning to account for these requriements and does not expect similar delays to impact the Lathrop's EBCE enrollment should the Board approve the City's JPA membership. As a result, pending the Board's approval, Lathrop's anticipated start of EBCE service would begin in January 2025, along with Stockton.

Process

Given the requirements and timing articulated above, EBCE staff has drafted a document outlining the process to join EBCE in time to enroll customers in 2025 Please see attached: "Steps to Joining East Bay Community Energy (EBCE)."

The table below summarizes the City of Lathrop's EBCE membership consideration and implementation processes:

Date	Event
Oct '22-March '23	EBCE staff meet with Lathrop City staff at City's invitation. EBCE staff continue to engage and communicate with City staff.
March-May 2023	City completes PG&E load data request forms/non-disclosure agreements. EBCE staff receives load data from PG&E.
July-August 2023	City Council passes Resolution, Ordinance to join EBCE (attached). City Manager executes JPA signature page (attached).
August 2023	EBCE conducts quantitative analysis to evaluate City's JPA membership request (attached).
Sept-Oct 2023	Earliest opportunities for EBCE Executive Committee (Exec Com), Board of Directors (BoD) and Community Advisory Committee (CAC) to consider quantitative analysis, inclusion request(s), and updates to JPA Agreement Exhibits A, B and C.
Oct-Dec 2023	Latest opportunities for EBCE Exec Com, BoD and CAC to consider quantitative analysis, inclusion request(s), and updates to JPA Agreement Exhibits A, B and C. Pending affirmative Board vote, staff updates Exhibits, and files updated Implementation Plan with CPUC.
2024	City of Lathrop entitled to a seat on EBCE's Board of Directors; EBCE's community outreach to new communities begins. Some EBCE programs may become available to Lathrop's electricity customers (e.g. technical assistance w/energy resilience at critical municipal facilities).
2025	EBCE customer account enrollments begin in Lathrop (and Stockton)

Fiscal Impact

The prospect of including a new city within EBCE's Joint Powers Authority and service area—particularly one as rapidly growing and demographically diverse as Lathrop[6]—presents considerable financial implications for the Agency. For this reason, EBCE staff conducted a Quantitative Analysis (QA) using the City's annual PG&E load data (from calendar year 2022) to evaluate the cost of service to this prospective new member jurisdiction. The results of this analysis are included as an attachment to this report.[7]

[6] Lathrop has been identified by the State Department of Finance as one of the fastest growing cities in California: https://www.abc10.com/article/news/local/lathrop-growth-surge/103-245febe8-8751-4dea-9ce2-a3b6909095c6 & https://www.mantecabulletin.com/news/local-news/lathrop-californias-fastest-growing-city/
For an overview of Lathrop's demographics and community profile for 2022/23, please refer here: https://www.ci.lathrop.ca.us/sites/default/files/fileattachments/economic_development/page/10081/lathrop smart_community_profile_2022-23.pdf

[7] Please refer to the attached "Presentation: Lathrop EBCE Membership: Quantitative Analysis"

In short, the purpose of the QA was to help answer the following, basic question: *Can EBCE include Lathrop within its growing service area, while providing the same level of service (or better) offered to current JPA member-jurisdictions and their communities?* This level of service (also known as EBCE's "value proposition") offers customers competitive electricity rates with greater access to non-nuclear, carbon-free energy resources compared to standard PG&E service.[8]

Based on the results of the QA, staff is confident the answer to this question is 'yes'.

According to the QA, the additional electric load of Lathrop in 2022 would have yielded approximately $1.77 million to EBCE's net revenues, or an additional 1.6% to EBCE's overall net position for that year. For 2025, the QA estimates the addition of Lathrop would contribute an additional 0.9% to EBCE's overall net position. This would represent a small, but positive fiscal impact on EBCE and its existing communities and customer base. These additional net revenues could be used to supplement EBCE reserves, reduce retail rates, and/or expand funding for local renewable energy project development and energy-related programs (e.g., rebates for energy storage, electric vehicles and EV charging infrastructure).

The table below summarizes the findings of the QA:

	Lathrop *2022*	EBCE 2022	EBCE w/Lathrop (and Stockton*) 2025
Accounts	**7,300**	**642,400**	***766,000***
Annual Load*(GWh/yr)*	**184**	**6,552**	***8,220***
Peak Load *(MW)*	**49**	**1,636**	***2,237***
Net Position %	**+1.6%**	**+14.5%**	***+8%*** ***(+0.9% specifically due to Lathrop)***
Net Position $	**$1.77M**	**$109.99M**	***$197.99M***

*Stockton's EBCE enrollment was delayed until 2025 by CPUC Res E-5258

NOTES:
*Based on current overhead costs and 10-year average market values/forecasts;

[8] EBCE currently offers customers a Bright Choice electric rate discount of 5% (previously 3%); and a Renewable 100 premium of ¼ a penny per kilowatt-hour (previously $0.01/kWh), compared to PG&E standard rates. Meanwhile, draft power content forecasts for 2022 (the most recent year for which data is available) indicate that EBCE's non-nuclear carbon-free power will be more than 71% of total supply; while PG&E's is expected to be approximately 47%. Please refer to the Emissions Overview developed for EBCE's Board in June 2023: https://cdn.sanity.io/files/pc49kbjr/production/0b9774744b54508e7a00353085d003d475fdabe1.pdf

*Assumes 7% account opt out rate (slightly above EBCE's current service area-wide opt out rate);
*Applies EBCE's 2023 rates from 2023-24 budget development;
*Data excludes ineligible loads (e.g. BART, Direct Access, Standby);
*Uses 2022 PG&E load data for Lathrop;

Financial Stress Test: Modeling Wholesale Energy Market and Power Charge Indifference Adjustment (PCIA) Scenarios

To help the Board evaluate the financial risk associated with including the City of Lathrop, the QA included a "Financial Stress Test." Among other things, this test measured the impact of two key cost variables: 1) wholesale energy market prices; and 2) the Power Charge Indifference Adjustment (PCIA).[9]

For example, a financial scenario could include a sustained wholesale energy price environment in which prices remain at EBCE's median forecasted levels, while the PCIA increases dramatically (e.g., the PCIA climbing to the 5th percentile in cost,). Per the Board's rate-setting policies, EBCE absorbs the cost of the PCIA to ensure its value proposition to customers (i.e., Bright Choice customers receive a 5% discount compared to PG&E's standard rates; and Renewable 100 customers pay an additional ¼ cent per kilowatt-hour above PG&E rates). In other words, EBCE's rate discount for Bright Choice customers, and the slight premium for Renewable 100 customers, remains consistent, despite any fluctuations in the PCIA. As such, dramatic increases in the PCIA can negatively impact EBCE's financial position.

In these conditions, EBCE could still 'break even' (i.e., the Agency's costs would be roughly equal to revenues during the sample year). Nevertheless, even in circumstances in which the cost to serve Lathrop could exceed the amount EBCE receives in retail rate revenues, EBCE's financial position would very likely remain secure due to Lathrop's relatively small size. In other words, the cost to serve Lathrop's electricity load represents a fraction of EBCE's current, overall costs. Moreover, EBCE could take steps to mitigate the negative financial impacts of this scenario (e.g., by adjusting the Bright Choice discount from 5% to 4%).

EBCE staff also modeled a "worst case" scenario, defined as a sustained wholesale energy price environment in which costs vastly exceed forecasts (e.g., wholesale prices that are roughly 85% higher than forecasted, or in the 95th percentile).
To be clear, a scenario of this kind would not be a temporary 'spike' in energy costs due to a weather event like a cold snap or a heat wave; it would be a prolonged energy market disruption lasting approximately a year or more, and likely the result of catastrophic events (e.g. a war between energy-rich countries; or an

[9] The PCIA is a charge to ensure that both PG&E customers and those who have left PG&E to purchase electricity from other providers (e.g., EBCE and other community choice aggregators) pay for the above market costs for electric generation resources that were procured by PG&E on their behalf.

unprecedented natural disaster that destroys or extensively damages vast critical infrastructure, like natural gas pipelines and/or electric transmission networks).

Under these conditions, EBCE could experience costs that exceed revenues by approximately 33%.[10] Nevertheless, EBCE could still mitigate the financial impacts by 1) adjusting rates (e.g., reducing the Bright Choice discount/raising retail rates, and/or increasing the Renewable 100 premium); and 2) taking various cost-cutting measures (e.g., reducing the budgets of certain departments or programs).

While it is difficult to predict future energy market prices, or account for large-scale catastrophic events, the modeling and 'stress tests' routinely performed by EBCE staff provide a conservative lens through which to consider the City of Lathrop's membership request. As mentioned above, staff's goal was to determine whether EBCE could include Lathrop within its growing service area, while providing the same level of service offered to current JPA member-jurisdictions and their communities. Based on the results of the QA, staff is confident EBCE can do so.

Qualitative Considerations

Lastly, in addition to considering the governance and financial implications of Lathrop's EBCE membership, there are numerous qualitative benefits to consider as well. These include the following:

- **Diversity, Equity, and Inclusion (DEI)** - By expanding access to competitively priced renewable energy and related programs to growing, frontline communities in California's Central Valley, EBCE can continue to advance the Agency's goals around diversity, equity, and inclusion;

- **Environmental Justice** – For a variety of systemic, economic, geographic, topographic, historical, and socio-political reasons, air pollution (among other forms of pollution) in Lathrop and the greater San Joaquin Valley region represents an urgent public health challenge.[11] Pediatric asthma, in particular, is fairly widespread, affecting one in six children.[12] By providing alternatives to fossil fuel-based energy resources in the building, transportation, and agricultural sectors, EBCE can help advance environmental justice and increase the quality of life for local communities;

[10] The financial stress test assumes cost increase persist for an entire year. It estimates the cost of energy to be the percentage of additional load multiplied by the 2023-24 budgeted energy expenses. It does not include initial customer notification costs (e.g., four mailed enrollment notices, staff time, event fees, travel, etc.)

[11] https://www.kvpr.org/local-news/2022-05-20/low-income-san-joaquin-valley-families-struggle-to-get-asthma-services-through-new-state-program

[12] https://www.scientificamerican.com/article/climate-change-is-bad-news-for-california-children-with-asthma/

- **Local Programs** – Due to its location within a major highway corridor and a global hub for agriculture, industry, and light/medium/heavy-duty trucking and goods transport, Lathrop offers tremendous programmatic opportunities for EBCE's transportation and building electrification endeavors. EBCE staff has identified multiple program areas where collaboration can begin right away;

- **Legislation and Political Influence** – By welcoming new State Assembly/Senate districts and new Federal Congressional districts into EBCE's service area, EBCE's current communities and customers will benefit from greater representation in Sacramento and Washington DC through EBCE's legislative and regulatory advocacy efforts;

- **CCA Proliferation, Public Power, and Energy Democracy** – When fast-growing, demographcially diverse cities, like Lathrop, join California's CCA moment, they help catalyze public power and energy democracy throughout California by example. As with the cities of Tracy and Stockton, Lathrop's EBCE membership would likely have a compounding positive impact by influencing neighboring Central Valley jurisdictions to consider CCA generally and/or EBCE membership specifically.

While difficult to measure, perhaps, these qualitative benefits and opportunities should not be underestimated. By including the City of Lathrop within its service area, EBCE can cultivate a more demographically diverse customer base, while advancing sustainable development, environmental justice, and energy democracy in communities throughout California and the United States.

Staff Recommendation

1. Receive update and analysis on including the City of Lathrop within EBCE's service area;

2. Adopt a Resolution to approving the inclusion of the City of Lathrop within EBCE's Joint Powers Authority and service area, with customer enrollments to begin in 2025 and direct staff to update Exhibit A ("List of Parties"), Exhibit B ("Annual Energy Use"), and Exhibit C ("Voting Shares Vote").

3. Adopt a Resolution to authorize staff to update the Implementation Plan to reflect the inclusion of the City of Lathrop, and to submit the updated Implementation Plan to the California Public Utilities Commission (CPUC) before the end of calendar year 2023.

Attachments

A. Steps to Joining East Bay Community Energy;
B. Presentation: Quantitative Analysis - City of Lathrop EBCE Membership
C. Presentation: CEO Report - Update re City of Lathrop - 7.19.23 Board mtg
D. City of Lathrop's signed staff report re EBCE membership
E. City of Lathrop's signed Resolution to join EBCE;
F. City of Lathrop's signed Ordinance to join EBCE/implement CCA;
G. EBCE Resolution to include the City of Lathrop as a JPA member;
H. Current EBCE Joint Powers Agreement including Exhibits A, B and C;
I. Proposed updates to JPA Exhibits A, B and C to include the City of Lathrop;
J. EBCE Resolution authorizing EBCE staff to update EBCE's Implementation Plan and submit it to the CPUC by end of calendar year 2023;
K. City of Lathrop's signed EBCE JPA signature page
L. Presentation: City of Lathrop EBCE membership and analysis

EAST BAY COMMUNITY ENERGY

Steps to joining East Bay Community Energy (EBCE)

1) In-person meeting(s) with City staff and/or local elected officials;
- Submit PG&E load data release forms (Forms 79-1030 & 79-1031);
    i. May take more than four months to receive accurate PG&E data;
- Expedited timeline due to CPUC Res. E-4907;

2) Two or three presentations to Council:
- Informational/Discussion item;
- Vote #1: Ordinance & Resolution to join EBCE's Joint Powers Authority (JPA) Agreement;
- Vote #2: Ordinance – *Completed by August 2023 for 2025 enrollment*;

3) EBCE staff conducts quantitative analysis;
- Evaluates cost of service to prospective new community (e.g., impact on EBCE's revenues/net revenues and 2030 Clean Energy Goal);

4) EBCE Board and Community Advisory Committee review quantitative analysis and corresponding membership request(s); Board considers Resolution to include prospective new community;

5) Pending Board approval, EBCE updates Joint Powers Agreement and files amended Implementation Plan with CPUC <u>before 12/31/23</u>;

<u>2024</u>: Community outreach in new community;

- Elected official of new community entitled to seat on EBCE Board of Directors;

<u>2025</u>: EBCE enrollment of electricity accounts begins in new community

Attachment Staff Report Item 11B

City of Lathrop

August 30, 2023

Attachment Staff Report Item 11B

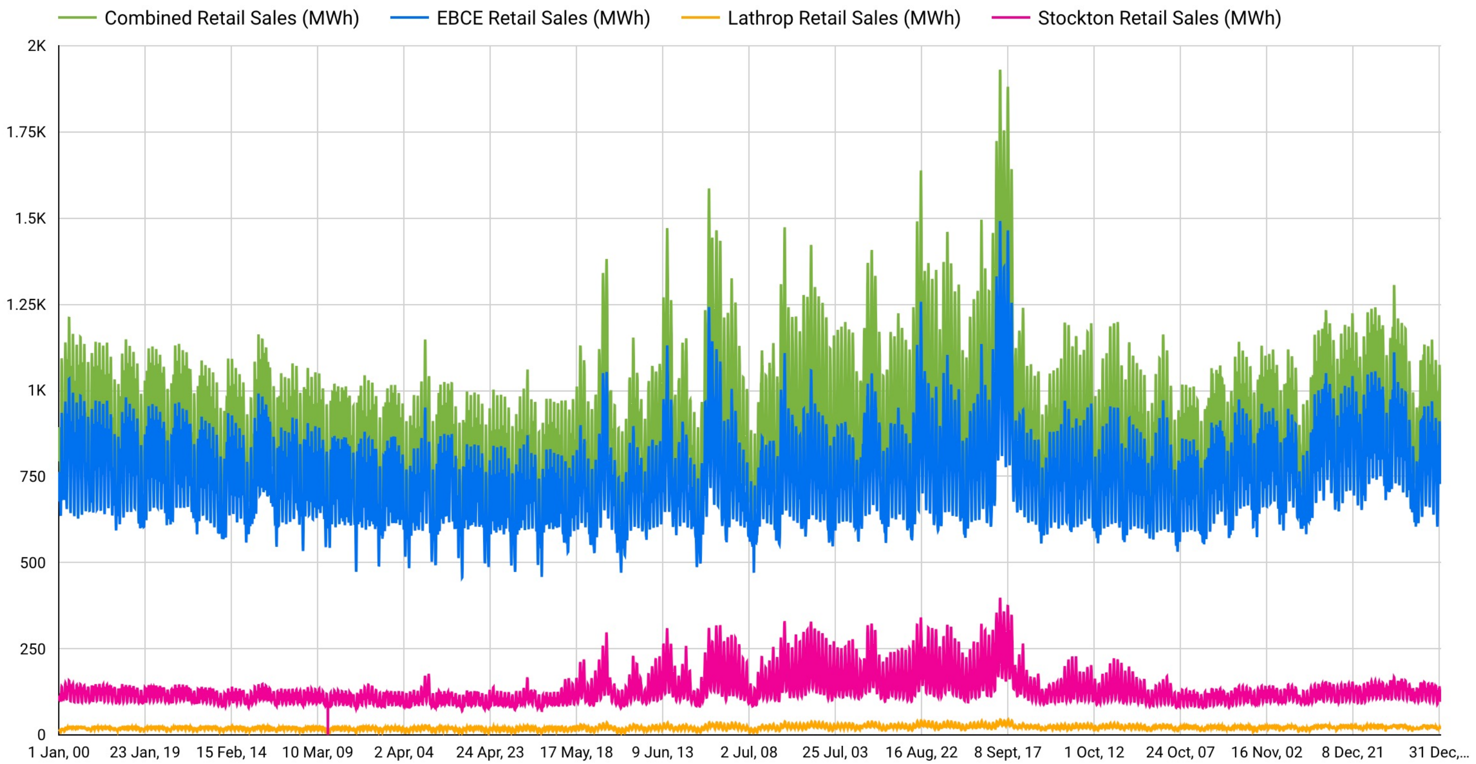
Summary Data

	Customer Count	Annual Load (GWh)	Peak Load (Wholesale MW)	Peak Date & Time (Hour Starting)
EBCE	641,776	6,552	1,636	2022-09-06 16:00
Stockton	111,740	1,154	438	2022-09-06 16:00
Lathrop	7,339	184	49	2022-09-06 17:00
Combined	760,855	7,890	2,120	2022-09-06 16:00

Rate Class	EBCE		Stockton		Lathrop		Combined	
	2022 MWh	%	2022 MWh	%	2022 MWh	%	2022 MWh	%
A1	945,379	14.4%	138,682	12.0%	10,212	5.5%	1,094,273	13.9%
A10	1,035,366	15.8%	159,405	13.8%	19,441	10.6%	1,214,213	15.4%
AGR	49,044	0.7%	1,462	0.1%	682	0.4%	51,189	0.6%
E19	1,316,623	20.1%	168,757	14.6%	55,779	30.3%	1,541,159	19.5%
E20	541,679	8.3%	75,230	6.5%	54,487	29.6%	671,396	8.5%
RES	2,615,021	39.9%	609,383	52.8%	42,344	23.0%	3,266,747	41.4%
LS	41,839	0.6%	97	0.0%	1,157	0.6%	43,092	0.5%
TC	7,070	0.1%	804	0.1%	134	0.1%	8,008	0.1%
Total	**6,552,021**	**100%**	**1,153,821**	**100%**	**184,237**	**100%**	**7,890,078**	**100%**

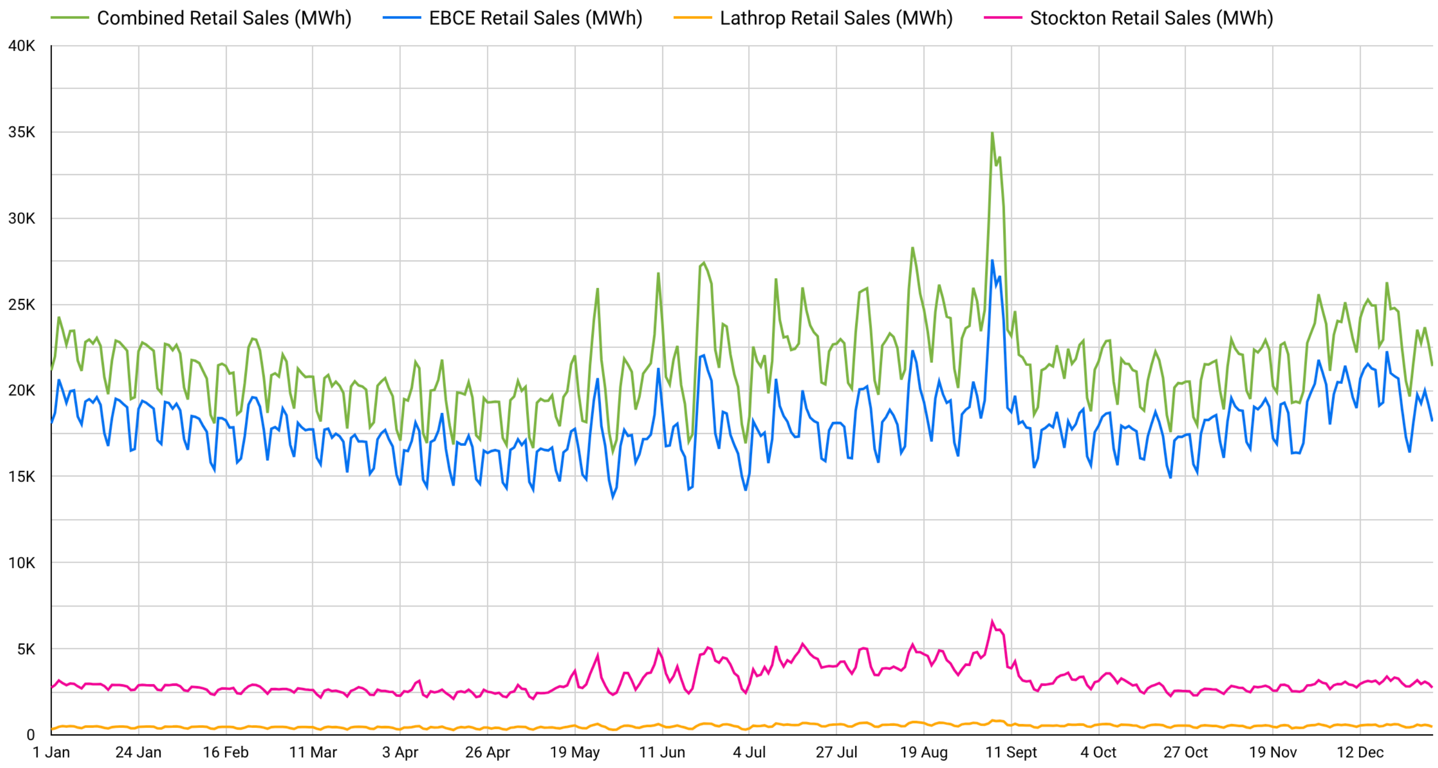
EAST BAY COMMUNITY ENERGY

2022 Hourly Load



EAST BAY COMMUNITY ENERGY

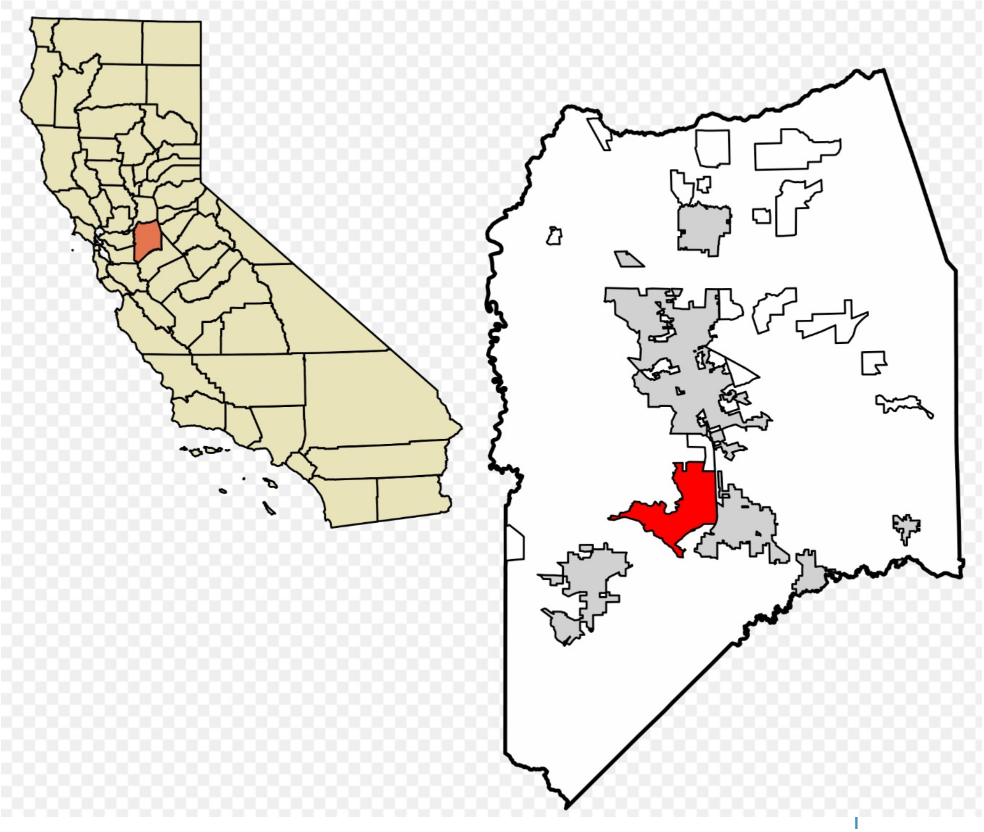
2022 Daily Load



EAST BAY COMMUNITY ENERGY

CITY OF LATHROP, CA

- **San Joaquin County: Between Tracy and Stockton**
  - Pop: 30,700 (2022)
  - Incorporated: 1989
  - Major transit intersection: Interstate 5 and CA State Route 120
  - Top three employers: Tesla, UPS, Army & Air Force Exchange Service
- **Energy-related opportunities**
  - Growing electricity load, particularly commercial & industrial sectors
  - Central location relative to agriculture, logistics, and shipping hubs
  - Interstate transit corridors for EV fast charging; light, medium, and heavy-duty fleets; and other transportation electrification projects



TIMELINE: LATHROP'S EBCE MEMBERSHIP

March 2023 – Presentation to City Council

July 2023 – Council considers joining JPA

In Process – EBCE conducts analysis

December 2023 – EBCE considers including new community; EBCE updates JPA

2024 – Community Outreach (with new name and brand)

2025 – EBCE enrolls new customers

Steps to Joining EBCE

1. Meetings with City staff/elected officials
2. 2-3 presentations to the City Council & Council considers joining JPA
3. EBCE staff conducts quantitative analysis
4. EBCE Board & Community Advisory Committee review analysis and Board considers including new community
5. If Board Approves, EBCE updates JPA and files amended Implementation Plan with the CPUC before 12/31/23

2024: Community outreach in new community

2025: EBCE enrolls customers in new community

EAST BAY COMMUNITY ENERGY

ITEM 5.1

CITY MANAGER'S REPORT
JULY 10, 2023 CITY COUNCIL REGULAR MEETING

ITEM:	**PUBLIC HEARING (PUBLISHED NOTICE) TO CONSIDER ADOPTING AN ORDINANCE TO IMPLEMENT A COMMUNITY CHOICE AGGREGATION PROGRAM AND ADOPTING RESOLUTION TO APPROVE A JOINT POWERS AGREEMENT WITH EAST BAY COMMUNITY (EBCE) AUTHORITY TO PROVIDE ELECTRIC SERVICES IN THE CITY OF LATHROP**
RECOMMENDATION:	**City Council to Consider the Following:** **1. Hold a Public Hearing; and** **2. First Reading and Introduction of an Ordinance to Implement a Community Choice Aggregation Program to Provide Electric Services in the City of Lathrop** **3. Adopt Resolution to Approve a Joint Powers Agreement with East Bay Community (EBCE) Authority to Provide Electric Services in the City of Lathrop**

SUMMARY:

On March 13, 2023 Council received a presentation from East Bay Community Energy (EBCE) regarding the benefits of implementing a Community Choice Aggregation (CCA) program. The potential benefits include lower electrical rates, local control and investment, and environmental sustainability.

Should Council want to proceed with the implementation of a CCA, the next step is to adopt an ordinance authorizing the City's implementation of a CCA program through EBCE along with a resolution approving a Joint Powers Agreement (JPA) to join the EBCE Joint Powers Authority.

BACKGROUND:

Community Choice Aggregation (CCA) was created in California by AB 117 (2002) and are governed by the California Public Utilities Commission (CPUC). CCAs are governmental entities formed by cities and counties to procure electricity for their residents, businesses, and municipal facilities. CCAs cannot be formed in the jurisdiction of a publicly owned electric utility (POU) that provides electrical service, this includes the Lathrop Irrigation District (LID) that provides electrical power within the River Islands Development.

CCA programs have several unique characteristics. When a CCA launches, investor-owned utility (IOU) electricity customers in the designated service area are automatically opted-in to CCA service, and have to opt out to continue to be served by the IOU.

For the City of Lathrop the IOU is Pacific Gas & Electric Co. (PG&E). Once established, a CCA purchases power for its customers. While the CCA is responsible for procurement, the IOU still provides other services such as transmission, distribution, metering, billing, collection, and customer service. Currently there are 25 CCA programs serving more than 11 million customers in California.

EBCE made a presentation to City Council at its March 13, 2023 meeting regarding participation and implementation of the CCA program to provide alternate electric services to City consumers under a JPA. In 2018, the County of Alameda and 11 of its cities launched EBCE as a not-for-profit public agency that governs this Community Choice Energy service. The Joint Power Agency expanded in 2021. The cities currently served are: Albany, Berkeley, Dublin, Emeryville, Fremont, Hayward, Livermore, Newark, Oakland, Piedmont, Pleasanton, San Leandro, Tracy, and Union City. The unincorporated areas of Alameda County (including Ashland, Castro Valley, Cherryland, Fairview, San Lorenzo, and Sunol) are also served by EBCE. The City of Stockton will begin EBCE service in 2025.

Section 366.2 of the California Public Utilities Code requires that any agency seeking to implement a CCA in their jurisdiction must do so by ordinance. This item requests that the City Council adopt an ordinance authorizing the City of Lathrop's implementation of a CCA program. The City Council must also adopt a resolution approving a joint powers agreement (JPA) thereby authorizing the EBCE to act as the CCA on the City's behalf.

The JPA contains provisions regarding as EBCE's powers, governance structure, including voting allocations, its obligation to indemnify the members, and the process for withdrawing from the authority, along with other standard JPA terms. As a member of EBCE, the City will have a representative on the EBCE's board of directors. If approved by Council, the JPA would be updated to reference the City of Lathrop.

REASON FOR RECOMMENDATION:

Adopting the proposed ordinance and approving the JPA with EBCE has the potential to provide lower electrical rates, local control and investment, and environmental sustainability.

FISCAL IMPACT:

There is no direct fiscal impact associated with adopting an ordinance implementing a Community Choice Aggregation Program or approving a Joint Powers Agreement with the EBCE Authority to provide electric services to the City of Lathrop.

ATTACHMENTS:

A. Ordinance to Implement a Community Choice Aggregation Program to Provide Electric Services in the City of Lathrop

B. Resolution to Approve a Joint Powers Agreement with East Bay Community (EBCE) Authority to Provide Electric Services in the City of Lathrop

C. ECBE Joint Powers of Agreement

APPROVALS:

Cari James Finance Director	7-5-23 Date
Michael King Assistant City Manager	7-5-2023 Date
Salvador Navarrete City Attorney	7-3-2023 Date
Stephen J. Salvatore City Manager	7.5.23 Date

RESOLUTION NO. 23-5338

A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF LATHROP TO APPROVE A JOINT POWERS AGREEMENT WITH EAST BAY COMMUNITY (EBCE) AUTHORITY TO PROVIDE ELECTRIC SERVICES IN THE CITY OF LATHROP

WHEREAS, the City of Lathrop has an interest in achieving greater local involvement over the provision of electricity supply services, competitive electric rates, local control and investment, and environmental sustainability; and

WHEREAS, Assembly Bill 117 codified as Public Utilities Code Section 366.2 (the "Act"), authorizes any California city or county whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA); and

WHEREAS, The Act allows a CCA program to be carried out under a joint powers agreement entered into by entities that each have capacity to implement a CCA program individually. The joint powers agreement structure reduces the risks of implementing a CCA program by immunizing the financial assets of participants; and

WHEREAS, on March 13, 2023 Council received a presentation from East Bay Community Energy (EBCE) regarding the benefits of implementing a CCA program; and

WHEREAS, implementing a CCA program will likely provide multiple benefits to the residents, including lower electrical rates, local control and investment, and environmental sustainability; and

WHEREAS, Alameda County and cities in Alameda County have developed the EBCE Authority Joint Powers Agreement (JPA) which creates the East Bay Community Energy Authority (Authority) which will govern and operate the CCA program; and

WHEREAS, the Authority provides alternate electric services to consumers under a JPA with Alameda County and the vast majority of all cities in that county; and

WHEREAS, The Authority is interested in providing potential services to the City of Lathrop; and

NOW, THEREFORE, BE IT RESOLVED, that the City Council of the City of Lathrop does hereby approve a Joint Powers Agreement with East Bay Community (EBCE) Authority to provide electric services in the City of Lathrop.

The foregoing resolution was passed and adopted this 10th day of July 2023, by the following vote of the City Council, to wit:

AYES: Akinjo, Diallo, Torres-O'Callaghan, and Dhaliwal

NOES: None

ABSENT: Lazard

ABSTAIN: None

Sonny Dhaliwal, Mayor

ATTEST:

Teresa Vargas, City Clerk

APPROVED AS TO FORM:

Salvador Navarrete, City Attorney

ORDINANCE NO. 23-447

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF LATHROP TO IMPLEMENT A COMMUNITY CHOICE AGGREGATION PROGRAM TO PROVIDE ELECTRIC SERVICES IN THE CITY OF LATHROP

WHEREAS, The City of Lathrop has an interest in achieving greater local involvement over the provision of electricity supply services, competitive electric rates, local control and investment, and environmental sustainability; and

WHEREAS, Assembly Bill 117 codified as Public Utilities Code Section 366.2 (the "Act"), authorizes any California city or county whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA); and

WHEREAS, The Act allows a CCA program to be carried out under a joint powers agreement entered into by entities that each have capacity to implement a CCA program individually. The joint powers agreement structure reduces the risks of implementing a CCA program by immunizing the financial assets of participants; and

WHEREAS, implementing a CCA program will likely provide multiple benefits to the residents, including lower electrical rates, local control and investment, and environmental sustainability; and

WHEREAS, concurrent with the introduction of this ordinance, the City Council considered a resolution approving the East Bay Community Energy Authority Joint Powers Agreement; and

WHEREAS, proper notice of this public hearing was given to all respects as required by law; and

WHEREAS, the City Council has reviewed all written evidence and oral testimony presented to date.

NOW, THEREFORE, THE CITY COUNCIL OF THE CITY OF LATHROP DOES HEREBY ORDAIN AS FOLLOWS:

Section 1 Findings.

Based upon the findings set forth hereinabove, the City Council elects to participate in, and approves the implementation of a Community Choice Aggregation program within the City of Lathrop's jurisdiction by and through the East Bay Community Energy Authority.

This Ordinance is not intended to and shall not be construed or given effect in a manner that imposes upon the City or any officer or employee thereof a mandatory duty of care toward persons and property within or without the city so as to provide a basis of civil liability for damages, except as otherwise imposed by law.

Section 2 Environmental.

The passage of this ordinance is not a project under the California Environmental Quality Act (CEQA) because it does not involve any commitment to a specific project which may result in a potentially significant physical impact on the environment, as contemplated by Title 14, California Code of Regulations, Sections 15378, therefore, not subject to CEQA pursuant to CEQA Guidelines Section 15060.

Section 3. Severalbility

If any provisions of this Ordinance or application thereof to any person or circumstances is held invalid, such invalidity shall not effect other provisions or applications of the ordinance which can be given effect without the invalid provision or application, and to this end the provisions of this Ordinance are severable. The City Council hereby declares that it would have adopted this Ordinance irrespective of the validity of any particular portions thereof.

Section 4. Effective Date

This Ordinance shall take legal effect and be in force thirty (30) days from and after the date of its passage.

Section 5. Pubilication

Within fifteen (15) days after its final passage, the City Clerk shall cause a copy of this Ordinance to be published in full accordance with Section 36933 of the Government Code.

THIS ORDINANCE was introduced at a regular meeting of the City Council of the City of Lathrop on the 10th day of July 2023, and was **PASSED AND ADOPTED** at a regular meeting of the City Council of the City of Lathrop on the 14th day of August, 2023 by the following vote, to wit:

AYES:	Diallo, Lazard, Torres-O'Callaghan, and Akinjo
NOES:	None
ABSENT:	Dhaliwal
ABSTAIN:	None

Paul Akinjo, Vice Mayor

ATTEST:

Teresa Vargas, City Clerk

APPROVED AS TO FORM:

Salvador Navarrete, City Attorney

STATE OF CALIFORNIA)
COUNTY OF SAN JOAQUIN) ss.
CITY OF LATHROP)

I, Teresa Vargas, City Clerk of the City of Lathrop, California, do hereby certify that the foregoing Ordinance No. 23-447 was duly and regularly introduced at a regular meeting of the City Council on the 10th day of July 2023, and that thereafter said Ordinance was duly and regularly adopted at a regular meeting of the City Council on the 14th day of August 2023, by the following vote, to wit:

AYES: Diallo, Lazard, Torres-O'Callaghan, and Akinjo

NOES: None

ABSENT: Dhaliwal

ABSTAIN: None

This Ordinance was duly published in accordance with State Law (G.C. 40806).

I hereby certify that the foregoing is the original of Ordinance No. 23-447 duly and adopted by the City of Lathrop City Council at its regular meeting held August 14, 2023, and that the Summary of the Ordinance was published on August 1, 2023, and Full Reading on August 18, 2023 in the Manteca Bulletin Newspaper.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the official seal of the City of Lathrop, California, this 18th day of August 2023.

TERESA VARGAS, MMC
CITY CLERK

(SEAL)

RESOLUTION NO. XX

A RESOLUTION OF THE BOARD OF DIRECTORS OF THE EAST BAY COMMUNITY ENERGY AUTHORITY AUTHORIZING THE CITY OF LATHROP TO BECOME A PARTY TO THE JOINT POWERS AGREEMENT AND MEMBER OF EBCE

THE BOARD OF DIRECTORS OF THE EAST BAY COMMUNITY ENERGY AUTHORITY DOES HEREBY FIND, RESOLVE AND ORDER AS FOLLOWS:

WHEREAS, on September 24, 2002, the Governor of California signed into law Assembly Bill 117 (Stat. 2002, Ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation ("CCA"); and

WHEREAS, the Act expressly authorizes participation in a CCA program through a joint powers agency; and on December 1, 2016, the East Bay Community Energy Authority ("EBCE" or "the Agency") was formed under the Joint Exercise of Power Act, California Government Code sections 6500 *et seq.*, among the County of Alameda, and the Cities of Albany, Berkeley, Dublin, Emeryville, Fremont, Hayward, Livermore, Piedmont, Oakland, San Leandro, and Union City to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs in all of the member jurisdictions; and

WHEREAS, The East Bay Community Energy Authority ("EBCE") was formed as a community choice aggregation agency ("CCA") on December 1, 2016, Under the Joint Exercise of Power Act, California Government Code sections 6500 *et seq.*, among the County of Alameda, and the Cities of Albany, Berkeley, Dublin, Emeryville, Fremont, Hayward, Livermore, Piedmont, Oakland, San Leandro, and Union City to study, promote, develop, conduct, operate, and manage energy-related climate change programs in all of the member jurisdictions. The cities of Newark and Pleasanton, located in Alameda County, along with the City of Tracy, located in San Joaquin County, were added as members of EBCE and parties to the JPA in March of 2020. The city of Stockton, located in San Joaquin County was added as a member of EBCE and party to the JPA in September of 2022; and

WHEREAS, on November 8, 2017, the California Public Utilities Commission ("CPUC") certified the "Implementation Plan" of EBCE, confirming EBCE's compliance with the requirements of the Act; and

WHEREAS, Section 3.1 of the EBCE Joint Powers Agreement ("Agreement") sets forth the procedures for the addition of new member jurisdictions; and

WHEREAS, on November 20, 2019, EBCE's Board of Directors unanimously authorized the cities of Tracy, Pleasanton, and Newark to become new parties to the Agreement with EBCE service beginning in those jurisdictions in April 2021; and

WHEREAS, on December 20, 2019, EBCE submitted an updated "Implementation Plan" to the CPUC reflecting the membership of the cities of Tracy, Pleasanton, and Newark to the Agreement and EBCE service area; and

WHEREAS, on September 21, 2022, EBCE's Board of Directors unanimously authorized the City of Stockton to become a new party to the Agreement with EBCE service anticipated to begin in April 2024; and

WHEREAS, on December 8, 2022, EBCE submitted an updated "Implementation Plan" to the CPUC reflecting the membership of the City of Stockton to the Agreement and EBCE service area; and

WHEREAS, including new member jurisdictions within EBCE's Joint Powers Authority can benefit EBCE communities, customers, and the general public by 1) expanding access to competitively-priced renewable energy, innovative programs and equitable policies; 2) achieving greater economies of scale while accelerating the reduction of greenhouse gas emissions; 3) enhancing EBCE's financial strength through increased revenues and reserves; 4) diversifying the Agency's service area while advancing environmental justice in historically marginalized communities; 5) empowering local stakeholders with more direct representation before State-level regulators and elected officials; and 6) inspiring more cities and counties to explore public power options in California and nationwide; and

WHEREAS, on July 10, 2023, through a unanimous vote of its City Council, the City of Lathrop expressed its intention of joining EBCE and participating in the Agency's CCA program by passing a resolution to request membership in EBCE and introducing an ordinance to implement a CCA program as required by Public Utilities Code section 366.2; and the ordinance was formally adopted on August 14, 2023; and

WHEREAS, EBCE conducted a quantitative analysis to examine the cost of service to the City of Lathrop, which indicated positive financial and environmental benefits from their membership to the prospective City as well as to EBCE's current communities and customer base; and,

WHEREAS, per CPUC rules, prospective member jurisdictions must join EBCE before the end of calendar year 2023 to begin customer enrollments in EBCE's service options by 2025; and

WHEREAS, Section 3.1 of the Agreement requires the Board of Directors to adopt a resolution authorizing the membership of additional member jurisdictions, and specifying the membership payment and conditions for membership, if any.

NOW, THEREFORE, THE BOARD OF DIRECTORS OF THE EAST BAY COMMUNITY ENERGY AUTHORITY DOES HEREBY RESOLVE AS FOLLOWS:

Section 1. The City of Lathrop is hereby authorized to become a party to the Agreement and a member of EBCE, subject to the following conditions:

(a) The Community Choice Aggregation ordinance adopted by the City of Lathrop becoming effective.

(b) The execution of the Agreement by the duly authorized official of the City of Lathrop.

Section 2. Staff are hereby directed to revise Exhibits A, B, and C of the Agreement to include Lathrop as a member of EBCE and to provide updated energy load information. Revised Exhibits are attached to this Resolution and incorporated herein.

Section 3. The CEO and General Counsel are hereby authorized to take all necessary implementing actions to effectuate this Resolution, including but not limited to filing a revised Agreement with the Secretary of State and applicable Local Agency Formation Commissions, as required by state law.

ADOPTED AND APPROVED this 20th day of September, 2023.

____

Elisa Márquez, Chair

ATTEST:

____

Adrian Bankhead, Secretary

East Bay Community Energy Authority

- Joint Powers Agreement -

Effective December 1, 2016
As amended by Resolution No. 2018-23 dated June 20, 2018 and
Resolution No. 2022-28 dated September 21, 2022

County of Alameda

City of Albany

City of Berkeley

City of Dublin

City of Emeryville

City of Fremont

City of Hayward

City of Livermore

City of Newark

City of Oakland

City of Piedmont

City of Pleasanton

City of San Leandro

City of Stockton

City of Tracy

City of Union City

EAST BAY COMMUNITY ENERGY AUTHORITY

JOINT POWERS AGREEMENT

This Joint Powers Agreement ("Agreement"), effective as of December 1, 2016, is made and entered into pursuant to the provisions of Title 1, Division 7, Chapter 5, Article 1 (Section 6500 *et seq.*) of the California Government Code relating to the joint exercise of powers among the parties set forth in Exhibit A ("Parties"). The term "Parties" shall also include an incorporated municipality or county added to this Agreement in accordance with Section 3.1.

RECITALS

1. The Parties are either incorporated municipalities or counties sharing various powers under California law, including but not limited to the power to purchase, supply, and aggregate electricity for themselves and their inhabitants.

2. In 2006, the State Legislature adopted AB 32, the Global Warming Solutions Act, which mandates a reduction in greenhouse gas emissions in 2020 to 1990 levels. The California Air Resources Board is promulgating regulations to implement AB 32 which will require local government to develop programs to reduce greenhouse gas emissions.

3. The purposes for the Initial Participants (as such term is defined in Section 1.1.16 below) entering into this Agreement include securing electrical energy supply for customers in participating jurisdictions, addressing climate change by reducing energy related greenhouse gas emissions, promoting electrical rate price stability, and fostering local economic benefits such as jobs creation, community energy programs and local power development. It is the intent of this Agreement to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including but not limited to State, regional and local solar and wind energy production.

4. The Parties desire to establish a separate public agency, known as the East Bay Community Energy Authority ("Authority"), under the provisions of the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq.*) ("Act") in order to collectively study, promote, develop, conduct, operate, and manage energy programs.

5. The Initial Participants have each adopted an ordinance electing to implement through the Authority a Community Choice Aggregation program pursuant to California Public Utilities Code Section 366.2 ("CCA Program"). The first priority of the Authority will be the consideration of those actions necessary to implement the CCA Program.

6. By establishing the Authority, the Parties seek to:

   (a) Provide electricity rates that are lower or competitive with those offered by PG&E for similar products;

(b) Offer differentiated energy options (e.g. 33% or 50% qualified renewable) for default service, and a 100% renewable content option in which customers may "opt-up" and voluntarily participate;

(c) Develop an electric supply portfolio with a lower greenhouse gas (GHG) intensity than PG&E, and one that supports the achievement of the parties' greenhouse gas reduction goals and the comparable goals of all participating jurisdictions;

(d) Establish an energy portfolio that prioritizes the use and development of local renewable resources and minimizes the use of unbundled renewable energy credits;

(e) Promote an energy portfolio that incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals;

(f) Demonstrate quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);

(g) Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California. The Authority, as a leader in the shift to a clean energy, commits to ensuring it will take steps to minimize any adverse impacts to these workers to ensure a "just transition" to the new clean energy economy;

(h) Deliver clean energy programs and projects using a stable, skilled workforce through such mechanisms as project labor agreements, or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;

(i) Promote personal and community ownership of renewable resources, spurring equitable economic development and increased resilience, especially in low income communities;

(j) Provide and manage lower cost energy supplies in a manner that provides cost savings to low-income households and promotes public health in areas impacted by energy production; and

(k) Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize, and providing appropriate wages and benefits.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises, covenants, and conditions hereinafter set forth, it is agreed by and among the Parties as follows:

ARTICLE 1
CONTRACT DOCUMENTS

1.1 Definitions. Capitalized terms used in the Agreement shall have the meanings specified below, unless the context requires otherwise.

1.1.1 "AB 117" means Assembly Bill 117 (Stat. 2002, ch. 838, codified at Public Utilities Code Section 366.2), which created CCA.

1.1.2 "Act" means the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq*.)

1.1.3 "Agreement" means this Joint Powers Agreement.

1.1.4 "Annual Energy Use" has the meaning given in Section 1.1.23.

1.1.5 "Authority" means the East Bay Community Energy Authority established pursuant to this Joint Powers Agreement.

1.1.6 "Authority Document(s)" means document(s) duly adopted by the Board by resolution or motion implementing the powers, functions and activities of the Authority, including but not limited to the Operating Rules and Regulations, the annual budget, and plans and policies.

1.1.7 "Board" means the Board of Directors of the Authority.

1.1.8 "Community Choice Aggregation" or "CCA" means an electric service option available to cities and counties pursuant to Public Utilities Code Section 366.2.

1.1.9 "CCA Program" means the Authority's program relating to CCA that is principally described in Sections 2.4 and 5.1.

1.1.10 "Days" shall mean calendar days unless otherwise specified by this Agreement.

1.1.11 "Director" means a member of the Board of Directors representing a Party, including an alternate Director.

1.1.12 "Effective Date" means the date on which this Agreement shall become effective and the East Bay Community Energy Authority shall exist as a separate public agency, as further described in Section 2.1.

1.1.13 "Ex Officio Board Member" means a non-voting member of the Board of Directors as described in Section 4.2.2. The Ex Officio Board Member may not serve on the Executive Committee of the Board or participate in closed session meetings of the Board.

1.1.14 "Implementation Plan" means the plan generally described in Section 5.1.2 of this Agreement that is required under Public Utilities Code Section 366.2 to be filed with the California Public Utilities Commission for the purpose of describing a proposed CCA Program.

1.1.15 "Initial Costs" means all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as the hiring of a Chief Executive Officer and any administrative staff, any required accounting, administrative, technical and legal services in support of the Authority's initial formation activities or in support of the negotiation, preparation and approval of power purchase agreements. The Board shall determine the termination date for Initial Costs.

1.1.16 "Initial Participants" means, for the purpose of this Agreement the County of Alameda, the Cities of Albany, Berkeley, Emeryville, Oakland, Piedmont, San Leandro, Hayward, Union City, Fremont, Dublin, and Livermore.

1.1.17 "Operating Rules and Regulations" means the rules, regulations, policies, bylaws and procedures governing the operation of the Authority.

1.1.18 "Parties" means, collectively, the signatories to this Agreement that have satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.

1.1.19 "Party" means, singularly, a signatory to this Agreement that has satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.

1.1.20 "Percentage Vote" means a vote taken by the Board pursuant to Section 4.12.1 that is based on each Party having one equal vote.

1.1.21 "Total Annual Energy" has the meaning given in Section 1.1.23.

1.1.22 "Voting Shares Vote" means a vote taken by the Board pursuant to Section 4.12.2 that is based on the voting shares of each Party described in Section 1.1.23 and set forth in Exhibit C to this Agreement. A Voting Shares vote cannot take place on a matter unless the matter first receives an affirmative or tie Percentage Vote in the manner required by Section 4.12.1 and three or more Directors immediately thereafter request such vote.

1.1.23 "Voting Shares Formula" means the weight applied to a Voting Shares Vote and is determined by the following formula:

(Annual Energy Use/Total Annual Energy) multiplied by 100, where (a) "Annual Energy Use" means (i) with respect to the first two years following the Effective Date, the annual electricity usage, expressed in kilowatt hours ("kWh"), within the Party's respective jurisdiction and (ii) with respect to the period after the second anniversary of the Effective Date, the annual electricity usage, expressed in kWh, of accounts within a Party's respective jurisdiction that are served by the Authority and (b) "Total Annual Energy" means the sum of all Parties' Annual Energy Use. The initial values for Annual Energy use are designated in Exhibit B and the initial voting shares are designated in Exhibit C. Both Exhibits B and C shall be adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 of each year subject to the approval of the Board.

1.2 Documents Included. This Agreement consists of this document and the following exhibits, all of which are hereby incorporated into this Agreement.

Exhibit A: List of the Parties

Exhibit B: Annual Energy Use

Exhibit C: Voting Shares

1.3 Revision of Exhibits. The Parties agree that Exhibits A, B and C to this Agreement describe certain administrative matters that may be revised upon the approval of the Board, without such revision constituting an amendment to this Agreement, as described in Section 8.4. The Authority shall provide written notice to the Parties of the revision of any such exhibit.

ARTICLE 2
FORMATION OF EAST BAY COMMUNITY ENERGY AUTHORITY

2.1 Effective Date and Term. This Agreement shall become effective and East Bay Community Energy Authority shall exist as a separate public agency on December 1, 2016, provided that this Agreement is executed on or prior to such date by at least three Initial Participants after the adoption of the ordinances required by Public Utilities Code Section 366.2(c)(12). The Authority shall provide notice to the Parties of the Effective Date. The Authority shall continue to exist, and this Agreement shall be effective, until this Agreement is terminated in accordance with Section 7.3, subject to the rights of the Parties to withdraw from the Authority.

2.2 Initial Participants. Until December 31, 2016, all other Initial Participants may become a Party by executing this Agreement and delivering an executed copy of this Agreement and a copy of the adopted ordinance required by Public Utilities Code Section 366.2(c)(12) to the Authority. Additional conditions, described in Section 3.1, may apply (i) to either an incorporated municipality or county desiring to become a Party that is not an Initial Participant and (ii) to Initial Participants that have not executed and delivered this Agreement within the time period described above.

2.3 **Formation**. There is formed as of the Effective Date a public agency named the East Bay Community Energy Authority. Pursuant to Sections 6506 and 6507 of the Act, the Authority is a public agency separate from the Parties. The debts, liabilities or obligations of the Authority shall not be debts, liabilities or obligations of the individual Parties unless the governing board of a Party agrees in writing to assume any of the debts, liabilities or obligations of the Authority. A Party who has not agreed to assume an Authority debt, liability or obligation shall not be responsible in any way for such debt, liability or obligation even if a majority of the Parties agree to assume the debt, liability or obligation of the Authority. Notwithstanding Section 8.4 of this Agreement, this Section 2.3 may not be amended unless such amendment is approved by the governing boards of all Parties.

2.4 **Purpose**. The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party and any other powers granted to the Authority under state law to participate as a group in the CCA Program pursuant to Public Utilities Code Section 366.2(c)(12); to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs; and, to exercise all other powers necessary and incidental to accomplishing this purpose.

2.5 **Powers**. The Authority shall have all powers common to the Parties and such additional powers accorded to it by law. The Authority is authorized, in its own name, to exercise all powers and do all acts necessary and proper to carry out the provisions of this Agreement and fulfill its purposes, including, but not limited to, each of the following:

2.5.1 to make and enter into contracts, including those relating to the purchase or sale of electrical energy or attributes thereof;

2.5.2 to employ agents and employees, including but not limited to a Chief Executive Officer and General Counsel;

2.5.3 to acquire, contract, manage, maintain, and operate any buildings, works or improvements, including electric generating facilities;

2.5.4 to acquire property by eminent domain, or otherwise, except as limited under Section 6508 of the Act, and to hold or dispose of any property;

2.5.5 to lease any property;

2.5.6 to sue and be sued in its own name;

2.5.7 to incur debts, liabilities, and obligations, including but not limited to loans from private lending sources pursuant to its temporary borrowing powers such as Government Code Section 53850 *et seq*. and authority under the Act;

2.5.8 to form subsidiary or independent corporations or entities, if appropriate, to carry out energy supply and energy conservation programs at the lowest possible cost consistent with the Authority's CCA Program implementation plan, risk management policies, or to take advantage of legislative or regulatory changes;

2.5.9 to issue revenue bonds and other forms of indebtedness;

2.5.10 to apply for, accept, and receive all licenses, permits, grants, loans or other assistance from any federal, state or local public agency;

2.5.11 to submit documentation and notices, register, and comply with orders, tariffs and agreements for the establishment and implementation of the CCA Program and other energy programs;

2.5.12 to adopt rules, regulations, policies, bylaws and procedures governing the operation of the Authority ("Operating Rules and Regulations");

2.5.13 to make and enter into service, energy and any other agreements necessary to plan, implement, operate and administer the CCA Program and other energy programs, including the acquisition of electric power supply and the provision of retail and regulatory support services; and

2.5.14 to negotiate project labor agreements, community benefits agreements and collective bargaining agreements with the local building trades council and other interested parties.

2.6 **Limitation on Powers**. As required by Government Code Section 6509, the power of the Authority is subject to the restrictions upon the manner of exercising power possessed by the City of Emeryville and any other restrictions on exercising the powers of the Authority that may be adopted by the Board.

2.7 **Compliance with Local Zoning and Building Laws**. Notwithstanding any other provisions of this Agreement or state law, any facilities, buildings or structures located, constructed or caused to be constructed by the Authority within the territory of the Authority shall comply with the General Plan, zoning and building laws of the local jurisdiction within which the facilities, buildings or structures are constructed and comply with the California Environmental Quality Act ("CEQA").

2.8 **Compliance with the Brown Act**. The Authority and its officers and employees shall comply with the provisions of the Ralph M. Brown Act, Government Code Section 54950 *et seq*.

2.9 **Compliance with the Political Reform Act and Government Code Section 1090.** The Authority and its officers and employees shall comply with the Political Reform Act (Government Code Section 81000 *et seq.*) and Government Code Section 1090 *et seq*, and shall adopt a Conflict of Interest Code pursuant to Government Code Section 87300. The Board of

Directors may adopt additional conflict of interest regulations in the Operating Rules and Regulations.

ARTICLE 3
AUTHORITY PARTICIPATION

3.1 Addition of Parties. Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption by an affirmative vote of a majority of all Directors of the entire Board satisfying the requirements described in Section 4.12, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(12) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership fee, if any, and (e) satisfaction of any conditions established by the Board.

3.2 Continuing Participation. The Parties acknowledge that membership in the Authority may change by the addition and/or withdrawal or termination of Parties. The Parties agree to participate with such other Parties as may later be added, as described in Section 3.1. The Parties also agree that the withdrawal or termination of a Party shall not affect this Agreement or the remaining Parties' continuing obligations under this Agreement.

ARTICLE 4
GOVERNANCE AND INTERNAL ORGANIZATION

4.1 Board of Directors. The governing body of the Authority shall be a Board of Directors ("Board") consisting of one director for each Party appointed in accordance with Section 4.2.

4.2 Appointment of Directors. The Directors shall be appointed as follows:

4.2.1 The governing body of each Party shall appoint and designate in writing one regular Director who shall be authorized to act for and on behalf of the Party on matters within the powers of the Authority. The governing body of each Party also shall appoint and designate in writing one alternate Director who may vote on matters when the regular Director is absent from a Board meeting. The person appointed and designated as the regular Director shall be a member of the governing body of the Party at the time of appointment but may continue to serve as a Director following his/her term as a member of the Party's governing body until a new Director is appointed pursuant to the timing in Section 4.3. The person appointed and designated as the alternate Director shall also be a member of the governing body of a Party and the alternate may continue to serve as an alternate following his/her term as a member of a Party's governing body until a new alternate is appointed pursuant to the timing in Section 4.3.

4.2.2 The Board shall also include one non-voting ex officio member as defined in Section 1.1.13 ("Ex Officio Board Member"). The Chair of the Community Advisory Committee, as described in Section 4.9 below, shall serve as the Ex Officio Board Member. The Vice Chair of the Community Advisory Committee shall serve as an alternate Ex Officio Board Member when the regular Ex Officio Board Member is absent from a Board meeting.

4.2.3 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.12 may include rules regarding Directors, such as meeting attendance requirements. No Party shall be deprived of its right to seat a Director on the Board.

4.3 **Term of Office**. Each regular and alternate Director shall serve at the pleasure of the governing body of the Party that the Director represents and may be removed as Director by such governing body at the time. If at any time a vacancy occurs on the Board because a Director is no longer a member of a Party's governing body, the Party shall appoint a replacement to fill the position of the previous Director in accordance with the provisions of Section 4.2.1 within ninety (90) days of the date that such Director is no longer a member of a Party's governing body or for any other reason that such position becomes vacant.

4.4 **Quorum**. A majority of the Directors of the entire Board shall constitute a quorum, except that less than a quorum may adjourn a meeting from time to time in accordance with law.

4.5 **Powers and Function of the Board**. The Board shall conduct or authorize to be conducted all business and activities of the Authority, consistent with this Agreement, the Authority Documents, the Operating Rules and Regulations, and applicable law. Board approval shall be required for any of the following actions, which are defined as "Essential Functions":

4.5.1 The issuance of bonds or any other financing even if program revenues are expected to pay for such financing.

4.5.2 The hiring of a Chief Executive Officer and General Counsel.

4.5.3 The appointment or removal of an officer.

4.5.4 The adoption of the Annual Budget.

4.5.5 The adoption of an ordinance.

4.5.6 The initiation of resolution of claims and litigation where the Authority will be the defendant, plaintiff, petitioner, respondent, cross complainant or cross petitioner, or intervenor; provided, however, that the Chief

Executive Officer or General Counsel, on behalf of the Authority, may intervene in, become party to, or file comments with respect to any proceeding pending at the California Public Utilities Commission, the Federal Energy Regulatory Commission, or any other administrative agency, without approval of the Board. The Board shall adopt Operating Rules and Regulations governing the Chief Executive Officer and General Counsel's exercise of authority under this Section 4.5.6.

4.5.7 The setting of rates for power sold by the Authority and the setting of charges for any other category of service provided by the Authority.

4.5.8 Termination of the CCA Program.

4.6 **Executive Committee**. The Board shall establish an Executive Committee consisting of a smaller number of Directors. The Board may delegate to the Executive Committee such authority as the Board might otherwise exercise, subject to limitations placed on the Board's authority to delegate certain Essential Functions, as described in Section 4.5 and the Operating Rules and Regulations. The Board may not delegate to the Executive Committee or any other committee its authority under Section 2.5.12 to adopt and amend the Operating Rules and Regulations or its Essential Functions listed in Section 4.5. After the Executive Committee meets or otherwise takes action, it shall, as soon as practicable, make a report of its activities at a meeting of the Board.

4.7 **Director Compensation**. Directors shall receive a stipend of $100 per meeting, as adjusted to account for inflation, as provided for in the Authority's Operating Rules and Regulations.

4.8 **Commissions, Boards and Committees**. The Board may establish any advisory commissions, boards and committees as the Board deems appropriate to assist the Board in carrying out its functions and implementing the CCA Program, other energy programs and the provisions of this Agreement. The Board may establish rules, regulations, policies, bylaws or procedures to govern any such commissions, boards, or committees and shall determine whether members shall be compensated or entitled to reimbursement for expenses.

4.9 **Community Advisory Committee**. The Board shall establish a Community Advisory Committee consisting of nine members and three alternates, none of whom may be voting members of the Board. One alternate from the pool of three alternates may take the place of a Community Advisory Member when a Community Advisory Committee member cannot attend a meeting. The Community Advisory Committee member that is unable to attend a meeting must notify the alternates of their inability to attend and obtain confirmation that one of the Alternates can attend the Community Advisory Committee meeting in that member's place. The function of the Community Advisory Committee shall be to advise the Board of Directors on all subjects related to the operation of the CCA Program as set forth in a work plan adopted by the Board of Directors from time to time, with the exception of personnel and litigation decisions. The Community Advisory Committee is advisory only, and shall not have decision making authority, or receive any delegation of authority from the Board of Directors. The Board shall publicize the opportunity to serve on the Community Advisory Committee and shall appoint members of the Community Advisory Committee and Alternates from those individuals expressing interest in serving, and who represent a diverse cross-section of interests, skill sets and geographic regions. Members of the Community Advisory Committee shall serve staggered four-years terms (the first term of three of the members shall be two years, and four years thereafter), which may be renewed. A member or Alternate of the Community Advisory Committee may be removed by the Board of Directors by majority vote. The Board of Directors shall determine whether the Community Advisory Committee members will receive a stipend or be entitled to reimbursement of expenses.

4.10 Chief Executive Officer. The Board of Directors shall appoint a Chief Executive Officer for the Authority, who shall be responsible for the day-to-day operation and management of the Authority and the CCA Program. The Chief Executive Officer may exercise all powers of the Authority, including the power to hire, discipline and terminate employees as well as the power to approve any agreement, if the expenditure is authorized in the Authority's approved budget, except the powers specifically set forth in Section 4.5 or those powers which by law must be exercised by the Board of Directors. The Board of Directors shall provide procedures and guidelines for the Chief Executive Officer exercising the powers of the Authority in the Operating Rules and Regulations.

4.11 General Counsel. The Board of Directors shall appoint a General Counsel for the Authority, who shall be responsible for providing legal advice to the Board of Directors and overseeing all legal work for the Authority.

4.12 Board Voting.

4.12.1 Percentage Vote. Except when a supermajority vote is expressly required by this Agreement or the Operating Rules and Regulations, action of the Board on all matters shall require an affirmative vote of a majority of all Directors on the entire Board (a "Percentage Vote" as defined in Section 1.1.20). A supermajority vote is required by this Agreement for the matters addressed by Section 8.4. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, action of the Board shall require an affirmative Percentage Vote of the specified supermajority of all Directors on the entire Board. No action can be taken by the Board without an affirmative Percentage Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved by an affirmative "Voting Shares Vote," as defined in Section 1.1.22, if three or more Directors immediately request such vote.

4.12.2 Voting Shares Vote. In addition to and immediately after an affirmative percentage vote, three or more Directors may request that, a vote of the voting shares shall be held (a "Voting Shares Vote" as defined in Section 1.1.22). To approve an action by a Voting Shares Vote, the corresponding voting shares (as defined in Section 1.1.23 and Exhibit C) of all Directors voting in the affirmative shall exceed 50% of the voting share of all Directors on the entire Board, or such other higher voting shares percentage expressly required by this Agreement or the Operating Rules and Regulations. In the event that any one Director has a voting share that equals or exceeds that which is necessary to disapprove the matter being voted on by the Board, at least one other Director shall be required to vote in the negative in order to disapprove such matter. When a voting shares vote is held, action by the Board requires both an affirmative Percentage Vote and an affirmative Voting Shares Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved on an affirmative Voting Shares Vote. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, the supermajority vote is subject to the Voting Share Vote provisions of this Section 4.12.2, and the specified supermajority of all Voting Shares is required for approval of the action, if the provision of this Section 4.12.2 are triggered.

4.13 Meetings and Special Meetings of the Board. The Board shall hold at least four regular meetings per year, but the Board may provide for the holding of regular meetings at more frequent intervals. The date, hour and place of each regular meeting shall be fixed by resolution or ordinance of the Board. Regular meetings may be adjourned to another meeting time. Special and Emergency meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956 and 54956.5. Directors may participate in meetings telephonically, with full voting rights, only to the extent permitted by law.

4.14 Officers.

4.14.1 Chair and Vice Chair. Prior to the end of the fiscal year, the Directors shall elect, from among themselves, a Chair, who shall be the presiding officer of all Board meetings, and a Vice Chair, who shall serve in the absence of the Chair. The newly elected Chair and Vice Chair shall commence serving in those capacities on July 1, except that no separate election shall be required for Fiscal Year 2018-2019 and the Chair and Vice Chair elected in 2018 shall continue to serve until the end of the 2018-2019 Fiscal Year. The Chair and Vice Chair shall hold office for one year and serve no more than two consecutive terms, however, the total number of terms a Director may serve as Chair or Vice Chair is not limited. The office of either the Chair or Vice Chair shall be declared vacant and the Board shall make a new selection if: (a) the person serving dies, resigns, or ceases to be a member of the governing body of a Party that person represents, except if the person is continuing to serve on the Board after that person no longer serves on the governing body in conformance with section 4.2.1; (b) the Party that the person represents removes the person as its representative on the Board, or (c) the Party that the person represents withdraws from the Authority pursuant to the provisions of this Agreement.

4.14.2 Secretary. The Board shall appoint a Secretary, who need not be a member of the Board, who shall be responsible for keeping the minutes of all meetings of the Board and all other official records of the Authority.

4.14.3 Treasurer and Auditor. The Board shall appoint a qualified person to act as the Treasurer and a qualified person to act as the Auditor, neither of whom needs to be a member of the Board. The same person may not simultaneously hold both the office of Treasurer and the office of the Auditor of the Authority. Unless otherwise exempted from such requirement, the Authority shall cause an independent audit to be made annually by a certified public accountant, or public accountant, in compliance with Section 6505 of the Act. The Treasurer shall act as the depositary of the Authority and have custody of all the money of the Authority, from whatever source, and as such, shall have all of the duties and responsibilities specified in Section 6505.5 of the Act. The Board may require the Treasurer and/or Auditor to file with the Authority an official bond in an amount to be fixed by the Board, and if so requested, the Authority shall pay the cost of premiums associated with the bond. The Treasurer shall report directly to the Board and shall comply with the requirements of treasurers of incorporated municipalities. The Board may transfer the responsibilities of Treasurer to any person or entity as the law may provide at the time.

4.15 Administrative Services Provider. The Board may appoint one or more administrative services providers to serve as the Authority's agent for planning, implementing, operating and administering the CCA Program, and any other program approved by the Board, in accordance with the provisions of an Administrative Services Agreement. The appointed administrative services provider may be one of the Parties. The Administrative Services Agreement shall set forth the terms and conditions by which the appointed administrative services provider shall perform or cause to be performed all tasks necessary for planning, implementing, operating and administering the CCA Program and other approved programs. The Administrative Services Agreement shall set forth the term of the Agreement and the circumstances under which the Administrative Services Agreement may be terminated by the Authority. This section shall not in any way be construed to limit the discretion of the Authority to hire its own employees to administer the CCA Program or any other program.

4.16 Operational Audit. The Authority shall commission an independent agent to conduct and deliver at a public meeting of the Board an evaluation of the performance of the CCA Program relative to goals for renewable energy and carbon reductions. The Authority shall approve a budget for such evaluation and shall hire a firm or individual that has no other direct or indirect business relationship with the Authority. The evaluation shall be conducted at least once every two years.

ARTICLE 5
IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 Implementation of the CCA Program.

5.1.1 Enabling Ordinance. Prior to the execution of this Agreement, each Party shall adopt an ordinance in accordance with Public Utilities Code

Section 366.2(c)(12) for the purpose of specifying that the Party intends to implement a CCA Program by and through its participation in the Authority.

5.1.2 Implementation Plan. The Authority shall cause to be prepared an Implementation Plan meeting the requirements of Public Utilities Code Section 366.2 and any applicable Public Utilities Commission regulations as soon after the Effective Date as reasonably practicable. The Implementation Plan shall not be filed with the Public Utilities Commission until it is approved by the Board in the manner provided by Section 4.12.

5.1.3 Termination of CCA Program. Nothing contained in this Article or this Agreement shall be construed to limit the discretion of the Authority to terminate the implementation or operation of the CCA Program at any time in accordance with any applicable requirements of state law.

5.2 Other Authority Documents. The Parties acknowledge and agree that the operations of the Authority will be implemented through various documents duly adopted by the Board through Board resolution or minute action, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies defined as the Authority Documents by this Agreement. The Parties agree to abide by and comply with the terms and conditions of all such Authority Documents that may be adopted by the Board, subject to the Parties' right to withdraw from the Authority as described in Article 7.

5.3 Integrated Resource Plan. The Authority shall cause to be prepared an Integrated Resource Plan in accordance with CPUC regulations that will ensure the long-term development and administration of a variety of energy programs that promote local renewable resources, conservation, demand response, and energy efficiency, while maintaining compliance with the State Renewable Portfolio standard and customer rate competitiveness. The Authority shall prioritize the development of energy projects in Alameda and adjacent counties. Principal aspects of its planned operations shall be in a Business Plan as outlined in Section 5.4 of this Agreement.

5.4 Business Plan. The Authority shall cause to be prepared a Business Plan, which will include a roadmap for the development, procurement, and integration of local renewable energy resources as outlined in Section 5.3 of this Agreement. The Business Plan shall include a description of how the CCA Program will contribute to fostering local economic benefits, such as job creation and community energy programs. The Business Plan shall identify opportunities for local power development and how the CCA Program can achieve the goals outlined in Recitals 3 and 6 of this Agreement. The Business Plan shall include specific language detailing employment and labor standards that relate to the execution of the CCA Program as referenced in this Agreement. The Business Plan shall identify clear and transparent marketing practices to be followed by the CCA Program, including the identification of the sources of its electricity and explanation of the various types of electricity procured by the Authority. The Business Plan shall cover the first five (5) years of the operation of the CCA Program. Progress on the implementation of the Business Plan shall be subject to annual public review.

5.5 **Labor Organization Neutrality.** The Authority shall remain neutral in the event its employees, and the employees of its subcontractors, if any, wish to unionize.

5.6 **Renewable Portfolio Standards.** The Authority shall provide its customers renewable energy primarily from Category 1 eligible renewable resources, as defined under the California RPS and consistent with the goals of the CCA Program. The Authority shall not procure energy from Category 3 eligible renewable resources (unbundled Renewable Energy Credits or RECs) exceeding 50% of the State law requirements, to achieve its renewable portfolio goals. However, for Category 3 RECs associated with generation facilities located within its service jurisdiction, the limitation set forth in the preceding sentence shall not apply.

ARTICLE 6
FINANCIAL PROVISIONS

6.1 **Fiscal Year**. The Authority's fiscal year shall be 12 months commencing July 1 and ending June 30. The fiscal year may be changed by Board resolution.

6.2 **Depository**.

6.2.1 All funds of the Authority shall be held in separate accounts in the name of the Authority and not commingled with funds of any Party or any other person or entity.

6.2.2 All funds of the Authority shall be strictly and separately accounted for, and regular reports shall be rendered of all receipts and disbursements, at least quarterly during the fiscal year. The books and records of the Authority shall be open to inspection by the Parties at all reasonable times.

6.2.3 All expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its Operating Rules and Regulations. The Treasurer shall draw checks or warrants or make payments by other means for claims or disbursements not within an applicable budget only upon the prior approval of the Board.

6.3 **Budget and Recovery Costs**.

6.3.1 **Budget**. The initial budget shall be approved by the Board. The Board may revise the budget from time to time through an Authority Document as may be reasonably necessary to address contingencies and unexpected expenses. All subsequent budgets of the Authority shall be prepared and approved by the Board in accordance with the Operating Rules and Regulations.

6.3.2 **Funding of Initial Costs**. The County shall fund the Initial Costs of establishing and implementing the CCA Program. In the event that the CCA Program becomes operational, these Initial Costs paid by the County and any specified interest shall be included in the customer charges for electric services to the extent permitted by law, and the County shall be reimbursed from the payment of such charges by customers of the Authority. The Authority may establish a reasonable time period over which such costs are recovered. In the event that the CCA Program does not become operational, the County shall not be entitled to any reimbursement of the Initial Costs.

6.3.4 **Additional Contributions and Advances**. Pursuant to Government Code Section 6504, the Parties may in their sole discretion make financial contributions, loans or advances to the Authority for the purposes of the Authority set forth in this Agreement. The repayment of such contributions, loans or advances will be on the written terms agreed to by the Party making the contribution, loan or advance and the Authority.

ARTICLE 7
WITHDRAWAL AND TERMINATION

7.1 Withdrawal.

7.1.1 **General Right to Withdraw**. A Party may withdraw its membership in the Authority, effective as of the beginning of the Authority's fiscal year, by giving no less than 180 days advance written notice of its election to do so, which notice shall be given to the Authority and each Party. Withdrawal of a Party shall require an affirmative vote of the Party's governing board.

7.1.2 **Withdrawal Following Amendment**. Notwithstanding Section 7.1.1, a Party may withdraw its membership in the Authority following an amendment to this Agreement provided that the requirements of this Section 7.1.2 are strictly followed. A Party shall be deemed to have withdrawn its membership in the Authority effective 180 days after the Board approves an amendment to this Agreement if the Director representing such Party has provided notice to the other Directors immediately preceding the Board's vote of the Party's intention to withdraw its membership in the Authority should the amendment be approved by the Board.

7.1.3 **The Right to Withdraw Prior to Program Launch**. After receiving bids from power suppliers for the CCA Program, the Authority must provide to the Parties a report from the electrical utility consultant retained by the Authority comparing the Authority's total estimated electrical rates, the estimated greenhouse gas emissions rate and the amount of estimated renewable energy to be used with that of the incumbent utility. Within 30 days after receiving this report, through its City Manager or a person expressly authorized by the Party, any Party may immediately withdraw its membership in the Authority by providing written notice of withdrawal to the Authority if the report determines that any one of the following conditions exists: (1) the Authority is unable to provide total electrical rates, as part of its baseline offering to customers, that are equal to or lower than the incumbent utility, (2) the Authority is unable to provide electricity in a manner that has a lower greenhouse gas emissions rate than the incumbent utility, or (3) the Authority will use less qualified renewable energy than the incumbent utility. Any Party who withdraws from the Authority pursuant to this Section 7.1.3 shall not be entitled to any refund of the Initial Costs it has paid to the Authority prior to the date of withdrawal unless the Authority is later terminated pursuant to Section 7.3. In such event, any Initial Costs not expended by the Authority shall be returned to all Parties, including any Party that has withdrawn pursuant to this section, in proportion to the contribution that each made. Notwithstanding anything to the contrary in this Agreement, any Party who withdraws pursuant to this section shall not be responsible for any liabilities or obligations of the Authority after the date of withdrawal, including without limitation any liability arising from power purchase agreements entered into by the Authority.

7.2 Continuing Liability After Withdrawal; Further Assurances; Refund. A Party that withdraws its membership in the Authority under either Section 7.1.1 or 7.1.2 shall be responsible for paying its fair share of costs incurred by the Authority resulting from the Party's withdrawal, including costs from the resale of power contracts by the Authority to serve the Party's load and any similar costs directly attributable to the Party's withdrawal, such costs being limited to those contracts executed while the withdrawing Party was a member, and administrative costs associated thereto. The Parties agree that such costs shall not constitute a debt of the withdrawing Party, accruing interest, or having a maturity date. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's costs described above. Any amount of the Party's funds held by the Authority for the benefit of the Party that are not required to pay the Party's costs described above shall be returned to the Party. The withdrawing party and the Authority shall execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, as determined by the Board, to effectuate the orderly withdrawal of such Party from membership in the Authority. A withdrawing party has the right to continue to participate in Board discussions and decisions affecting customers of the CCA Program that reside or do business within the jurisdiction of the Party until the withdrawal's effective date.

7.3 Mutual Termination. This Agreement may be terminated by mutual agreement of all the Parties; provided, however, the foregoing shall not be construed as limiting the rights of a Party to withdraw its membership in the Authority, and thus terminate this Agreement with respect to such withdrawing Party, as described in Section 7.1.

7.4 Disposition of Property upon Termination of Authority. Upon termination of this Agreement as to all Parties, any surplus money or assets in possession of the Authority for use under this Agreement, after payment of all liabilities, costs, expenses, and charges incurred under this Agreement and under any Authority Documents, shall be returned to the then-existing Parties in proportion to the contributions made by each.

ARTICLE 8
MISCELLANEOUS PROVISIONS

8.1 Dispute Resolution. The Parties and the Authority shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Before exercising any remedy provided by law, a Party or the Parties and the Authority shall engage in nonbinding mediation in the manner agreed upon by the Party or Parties and the Authority. The Parties agree that each Party may specifically enforce this section 8.1. In the event that nonbinding mediation is not initiated or does not result in the settlement of a dispute within 120 days after the demand for mediation is made, any Party and the Authority may pursue any remedies provided by law.

8.2 Liability of Directors, Officers, and Employees. The Directors, officers, and employees of the Authority shall use ordinary care and reasonable diligence in the exercise of their powers and in the performance of their duties pursuant to this Agreement. No current or former Director, officer, or employee will be responsible for any act or omission by another Director, officer, or employee. The Authority shall defend, indemnify and hold harmless the individual current and former Directors, officers, and employees for any acts or omissions in the scope of their employment or duties in the manner provided by Government Code Section 995 *et seq*. Nothing in this section shall be construed to limit the defenses available under the law, to the Parties, the Authority, or its Directors, officers, or employees.

8.3 Indemnification of Parties. The Authority shall acquire such insurance coverage as the Board deems necessary to protect the interests of the Authority, the Parties and the public. Such insurance coverage shall name the Parties and their respective Board or Council members, officers, agents and employees as additional insureds. The Authority shall defend, indemnify and hold harmless the Parties and each of their respective Board or Council members, officers, agents and employees, from any and all claims, losses, damages, costs, injuries and liabilities of every kind arising directly or indirectly from the conduct, activities, operations, acts, and omissions of the Authority under this Agreement.

8.4 Amendment of this Agreement. This Agreement may be amended in writing by a two-thirds affirmative vote of the entire Board satisfying the requirements described in Section 4.12. Except that, any amendment to the voting provisions in Section 4.12 may only be made by a three-quarters affirmative vote of the entire Board. The Authority shall provide written notice to the Parties at least 30 days in advance of any proposed amendment being considered by the Board. If the proposed amendment is adopted by the Board, the Authority shall provide prompt written notice to all Parties of the effective date of such amendment along with a copy of the amendment.

8.5 Assignment. Except as otherwise expressly provided in this Agreement, the rights and duties of the Parties may not be assigned or delegated without the advance written consent of all of the other Parties, and any attempt to assign or delegate such rights or duties in contravention of this Section 8.5 shall be null and void. This Agreement shall inure to the benefit of, and be binding upon, the successors and assigns of the Parties. This Section 8.5 does not prohibit a Party from entering into an independent agreement with another agency, person, or entity regarding the financing of that Party's contributions to the Authority, or the disposition of proceeds which that Party receives under this Agreement, so long as such independent agreement does not affect, or purport to affect, the rights and duties of the Authority or the Parties under this Agreement.

8.6 **Severability**. If one or more clauses, sentences, paragraphs or provisions of this Agreement shall be held to be unlawful, invalid or unenforceable, it is hereby agreed by the Parties, that the remainder of the Agreement shall not be affected thereby. Such clauses, sentences, paragraphs or provision shall be deemed reformed so as to be lawful, valid and enforced to the maximum extent possible.

8.7 **Further Assurances**. Each Party agrees to execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, to effectuate the purposes and intent of this Agreement.

8.8 **Execution by Counterparts**. This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

8.9 **Parties to be Served Notice**. Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 72 hours after the deposit thereof (excluding Saturdays, Sundays and holidays) if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. In addition, a duplicate copy of all notices provided pursuant to this section shall be provided to the Director and alternate Director for each Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties. All notices required hereunder shall be delivered to:

The County of Alameda

Director, Community Development Agency
224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to [PARTY No. ____]

Office of the City Clerk

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Office of the City Manager/Administrator

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Office of the City Attorney

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if to [PARTY No._____]

Office of the City Clerk

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Office of the City Manager/Administrator

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Office of the City Attorney

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ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: _________________________________

Name: _______________________________

Title: _______________________________

Date: _______________________________

Party: _______________________________

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: Scott Haggerty

Name: Scott Haggerty

Title: Board President

Date: January 4, 2017

Party: County of Alameda

APPROVED AS TO FORM:

DONNA R. ZIEGLER, COUNTY COUNSEL

By: Andrea Weddle

Andrea L. Weddle
Chief Assistant County Counsel

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to [PARTY No. ____]

Office of the City Clerk
Eileen Harrington, Deputy
Eileen Harrington 12/2/16

Office of the City Manager/Administrator
Penelope Crumpley

Office of the City Attorney
Craig Labadie

if to [PARTY No._____]

Office of the City Clerk

Office of the City Manager/Administrator

Office of the City Attorney

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: D. Williams-Ridley

Name: Dee Williams-Ridley

Title: City Manager

Date: December 1, 2016

Party: City of Berkeley

APPROVED AS TO FORM

By Michael Woo
CITY ATTORNEY FOR THE
CITY OF BERKELEY

Registered by:

Ann-Marie Hogan
City Auditor

ATTEST for the City of Berkeley

Mark Numainville
City Clerk

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to [PARTY No. ____]

City of Dublin
City Manager
100 Civic Plaza
Dublin, CA 94568

Meyers Nave
City Attorney
555 12th Street, Suite 1500
Oakland, CA 94607

if to [PARTY No._____]

Office of the City Clerk

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Office of the City Manager/Administrator

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Office of the City Attorney

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ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: ______________________________
Christopher L. Foss, City Manager
City of Dublin

Date: 12/1/16

Party: ______________________________

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to: City of Emeryville

Office of the City Clerk
1333 Park Avenue
Emeryville, CA 94608

Office of the City Manager
1333 Park Avenue
Emeryville, CA 94608

Office of the City Attorney
1333 Park Avenue
Emeryville, CA 94608

if to [PARTY No._____]

Office of the City Clerk

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Office of the City Manager/Administrator

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Office of the City Attorney

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ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: Carolyn Lehr
Name: Carolyn Lehr
Title: City Manager
Date: 12-1-16
Party: City of Emeryville

APPROVED AS TO FORM:

Michael Guina
Michael A. Guina, City Attorney

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to [PARTY No. ____]

City of Fremont

Office of the City Clerk
3300 Capitol Ave., Building A
Fremont, CA 94538

Office of the City Manager/Administrator
3300 Capitol Ave., Building A
Fremont, CA 94538

Office of the City Attorney
3300 Capitol Ave., Building A
Fremont, CA 94538

if to [PARTY No._____]

Office of the City Clerk

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Office of the City Manager/Administrator

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Office of the City Attorney

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ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: Jessica von Borck

Name: Jessica von Borck

Title: Assistant City Manager

Date: 12-1-16

Party: ____________________

APPROVED AS TO FORM:

Debra Margolis

Debra S. Margolis
Assistant City Attorney

The County of Alameda

Director, Community Development Agency
224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

City of Hayward

Office of the City Manager
City of Hayward
777 B Street
Hayward, CA 94541

With a copy to:

Office of the City Attorney
City of Hayward
777 B Street
Hayward, CA 94541

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

CITY OF HAYWARD, A Municipal Corporation

Date of Approval: 12/16/2016

Kelly McAdoo, City Manager

ATTEST: Miriam Lens, City Clerk

APPROVED AS TO FORM

for
Michael Lawson, City Attorney

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to City of Livermore

City Clerk's Office
1052 South Livermore Avenue
Livermore, CA 94550

With a copy to:

Public Works Department
Attn: Public Works Manager
3500 Robertson Park Road
Livermore, CA 94550

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: ______________________

Name: Marc Roberts

Title: City Manager

Date: 1/4/2017

Party: City of Livermore

APPROVED AS TO FORM:

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to [PARTY No. ____]

Office of the City Clerk
1 FRANK H. OGAWA PLAZA
OAKLAND, CA 94612

Office of the City ~~Manager~~/Administrator
1 FRANK H. OGAWA PLAZA
OAKLAND, CA 94612

Office of the City Attorney

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if to [PARTY No._____]

Office of the City Clerk

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Office of the City Manager/Administrator

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Office of the City Attorney

____

____

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: Claudia Cappio for SBL

Name: CLAUDIA CAPPIO

Title: ASST CITY ADMINISTRATOR

Date: 12/27/16

Party: CITY OF OAKLAND

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: Jeff Wieler

Name: Jeffrey Wieler

Title: Mayor

Date: 12/19/16

Party: City of Piedmont

force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

8.9 **Parties to be Served Notice**. Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 72 hours after the deposit thereof (excluding Saturdays, Sundays and holidays) if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. In addition, a duplicate copy of all notices provided pursuant to this section shall be provided to the Director and alternate Director for each Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties. All notices required hereunder shall be delivered to:

The County of Alameda

Director, Community Development Agency
224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to the City of San Leandro

Office of the City Clerk
835 East 14th Street
San Leandro, CA 94577

Office of the City Manager/Administrator
835 East 14th Street
San Leandro, CA 94577
Office of the City Attorney
835 East 14th Street
San Leandro, CA 94577

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

CITY OF SAN LEANDRO

____
Chris Zapata, City Manager

Attest:

____
Tamika Greenwood, City Clerk

Approved as to Form:

______________________________ for
Richard D. Pio Roda, City Attorney

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to The City of Union City [PARTY No. 12]

Office of the City Clerk

Anna M. Brown, City Clerk
34009 Alvarado Niles Road
Union City, CA 94587

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: ______________________

Name: Mark Evanoff

Title: Deputy City Manager

Date: December 5, 2016

Party: The City of Union City

East Bay Community Energy (EBCE)
1999 Harrison Street, Suite 800
Oakland CA 94612

if to Newark

Office of the City Clerk
37101 Newark Boulevard
Newark, CA 94560

Office of the City Manager/Administrator
37101 Newark Boulevard
Newark, CA 94560

Office of the City Attorney
37101 Newark Boulevard
Newark, CA 94560

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: ______________________

Name: David J. Benoun

Title: City Manager

Date: November 18, 2019

Party: CITY OF NEWARK

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

CITY OF PLEASANTON, a municipal corporation

Date: November 21, 2019

Nelson Fialho, City Manager

ATTEST: Karen Diaz, City Clerk

APPROVED AS TO FORM:

for Daniel G. Sodergren, City Attorney

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: ______________________
Name: Robert Rickman
Title: Mayor
Date: 11-7-19

Party: City of Tracy

APPROVED AS TO FORM

____
Leticia Ramirez, City Attorney

ATTEST

____
Adrianne Richardson, City Clerk

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: ______________________

Name: Harry Black

Title: City Manager

Date: 9/16/22

Party: City of Stockton

ATTEST:
for CLERK OF THE CITY OF STOCKTON
By ______________________

FOUNDED JUNE 1849 · STOCKTON · INCORPORATED JULY 1850

APPROVED AS TO FORM AND CONTENT
By ______________________
City Attorney

EXHIBIT A

LIST OF THE PARTIES

This Exhibit A is effective as of September 21, 2022.

County of Alameda

City of Albany

City of Berkeley

City of Dublin

City of Emeryville

City of Fremont

City of Hayward

City of Livermore

City of Newark

City of Oakland

City of Piedmont

City of Pleasanton

City of San Leandro

City of Stockton

City of Tracy

City of Union City

EXHIBIT B

ANNUAL ENERGY USE

This Exhibit B is effective as of September 21, 2022.

Party	kWh (2021)
Albany	51,776,870
Berkeley	370,191,096
Dublin	254,391,482
Emeryville	170,415,886
Fremont	1,152,160,067
Hayward	685,960,209
Livermore	441,369,886
Newark	263,309,620
Oakland	1,749,739,631
Piedmont	29,230,795
Pleasanton	405,288,495
San Leandro	448,938,229
Stockton	1,388,481,371
Tracy	434,861,665
Unincorporated	471,391,155
Union City	269,516,289
Total	8,587,022,746

All data provided by PG&E

EXHIBIT C

VOTING SHARES

This Exhibit C is effective as of September 21, 2022.

Party	kWh (2021)	Voting Shares Section 4.12.2
Albany	51,776,870	0.6%
Berkeley	370,191,096	4.3%
Dublin	254,391,482	3.0%
Emeryville	170,415,886	2.0%
Fremont	1,152,160,067	13.4%
Hayward	685,960,209	8.0%
Livermore	441,369,886	5.1%
Newark	263,309,620	3.1%
Oakland	1,749,739,631	20.4%
Piedmont	29,230,795	0.3%
Pleasanton	405,288,495	4.7%
San Leandro	448,938,229	5.2%
Stockton	1,388,481,371	16.2%
Tracy	434,861,665	5.1%
Unincorporated	471,391,155	5.5%
Union City	269,516,289	3.1%
Total	8,587,022,746	100%

All data provided by PG&E

EXHIBIT A

LIST OF THE PARTIES

This Exhibit A is effective as of September 20, 2023.

County of Alameda

City of Albany

City of Berkeley

City of Dublin

City of Emeryville

City of Fremont

City of Hayward

City of Lathrop

City of Livermore

City of Newark

City of Oakland

City of Piedmont

City of Pleasanton

City of San Leandro

City of Stockton

City of Tracy

City of Union City

EXHIBIT B

ANNUAL ENERGY USE

This Exhibit B is effective as of September 20, 2023.

Party	kWh (2022*)
Albany	50,016,072
Berkeley	350,111,874
Dublin	250,811,690
Emeryville	173,586,542
Fremont	1,182,339,971
Hayward	681,289,470
Lathrop	183,070,584
Livermore	428,724,628
Newark	244,335,398
Oakland	1,713,563,058
Piedmont	28,595,451
Pleasanton	394,860,960
San Leandro	414,939,109
Stockton	1,153,820,553
Tracy	412,411,899
Unincorporated County	452,054,476
Union City	261,439,720
Total	8,375,971,455

*All data provided by PG&E

EXHIBIT C

VOTING SHARES

This Exhibit C is effective as of September 20, 2023

.

Party	kWh (2022*)	Voting Shares Section 4.12.2
Albany	50,016,072	0.6%
Berkeley	350,111,874	4.2%
Dublin	250,811,690	3.0%
Emeryville	173,586,542	2.1%
Fremont	1,182,339,971	14.1%
Hayward	681,289,470	8.1%
Lathrop	183,070,584	2.2%
Livermore	428,724,628	5.1%
Newark	244,335,398	2.9%
Oakland	1,713,563,058	20.5%
Piedmont	28,595,451	0.3%
Pleasanton	394,860,960	4.7%
San Leandro	414,939,109	5.0%
Stockton	1,153,820,553	13.8%
Tracy	412,411,899	4.9%
Unincorporated County	452,054,476	5.4%
Union City	261,439,720	3.1%
Total	8,375,971,455	100%

*All data provided by PG&E

RESOLUTION NO. XX

A RESOLUTION OF THE BOARD OF DIRECTORS OF THE EAST BAY COMMUNITY ENERGY AUTHORITY AUTHORIZING EBCE STAFF TO UPDATE EBCE's IMPLEMENTATION PLAN TO REFLECT THE INCLUSION OF A NEW MEMBER JURISDICTION AND SUBMIT THE UPDATED PLAN TO THE CPUC

THE BOARD OF DIRECTORS OF THE EAST BAY COMMUNITY ENERGY AUTHORITY DOES HEREBY FIND, RESOLVE AND ORDER AS FOLLOWS:

WHEREAS, The East Bay Community Energy Authority ("EBCE") was formed on December 1, 2016, under the Joint Exercise of Power Act, California Government Code sections 6500 *et seq.*, among the County of Alameda, and the Cities of Albany, Berkeley, Dublin, Emeryville, Fremont, Hayward, Livermore, Piedmont, Oakland, San Leandro, and Union City to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs in all of the member jurisdictions.

WHEREAS, on November 20, 2019, EBCE's Board of Directors unanimously authorized the cities of Tracy, Pleasanton, and Newark to become new parties to the Agreement with EBCE service beginning in those jurisdictions in April 2021; and

WHEREAS, on December 20, 2019, EBCE submitted an updated "Implementation Plan" to the CPUC reflecting the membership of the cities of Tracy, Pleasanton, and Newark to the Agreement and EBCE service area; and

WHEREAS, on September 21, 2022, EBCE's Board of Directors unanimously authorized the City of Stockton to become a new party to the Agreement with EBCE service anticipated to begin in April 2024; and

WHEREAS, on December 8, 2022, EBCE submitted an updated "Implementation Plan" to the CPUC reflecting the membership of the City of Stockton to the Agreement and EBCE service area; and

WHEREAS, the Board of Directors has approved Resolution XX to authorize the City of Lathrop to become a member of EBCE, with enrollments expected to begin in 2025;

WHEREAS, on February 8, 2018, the California Public Utilities Commission ("CPUC") passed Resolution E-4907, which requires a one year waiting period for jurisdictions intending to form or join a community choice aggregation ("CCA") program, like EBCE;

WHEREAS, in order to begin enrolling electricity customers in Lathrop by 2025, EBCE must submit to the CPUC an updated Implementation Plan and Statement of

Intent ("Implementation Plan") reflecting the inclusion of this new member jurisdiction before the end of the 2023 calendar year.

NOW, THEREFORE, THE BOARD OF DIRECTORS OF THE EAST BAY COMMUNITY ENERGY AUTHORITY DOES HEREBY RESOLVE AS FOLLOWS:

Section 1. The Board hereby authorizes EBCE staff to update EBCE's Implementation Plan, reflecting the membership of the City of Lathrop.

Section 2. The Board hereby directs staff to submit the updated Implementation Plan to the CPUC for certification as soon as reasonably feasible, before December 31, 2023.

ADOPTED AND APPROVED this 20th day of September, 2023.

____

Elisa Marquez, Chair

ATTEST:

____

Adrian Bankhead, Secretary

if to: City of Lathrop

Office of the City Clerk
390 Towne Centre Drive
Lathrop, CA 95330

Office of the City Manager
390 Towne Centre Drive
Lathrop, CA 95330

Office of the City Attorney
390 Towne Centre Drive
Lathrop, CA 95330

With a copy to:

Department of Public Works
39o Towne Centre Drive
Lathrop, CA 95330

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

CITY OF LATHROP,
A California municipal corporation of the
State of California

By: ______________________ 7.21.23
Stephen J. Salvatore Date
City Manager

ATTEST:
City Clerk of and for the City
of Lathrop, State of California

By: ______________________ 7/21/23
Teresa Vargas Date
City Clerk

APPROVED AS TO FORM BY THE CITY OF LATHROP CITY ATTORNEY

By: ______________________ 7-18-2023
Salvador Navarrete Date
City Attorney

Attachment Staff Report Item 11L

September 2023

Inclusion of New Communities: City of Lathrop

EAST BAY COMMUNITY ENERGY

City of Lathrop, CA

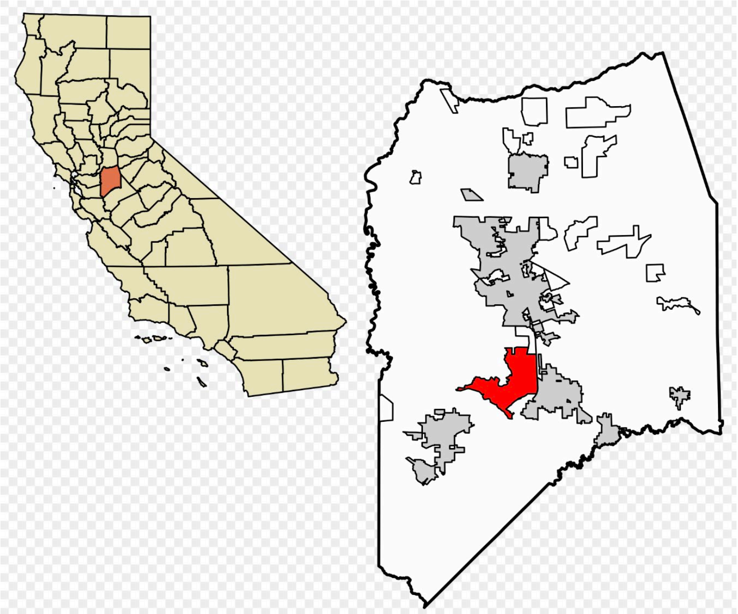
Located between Tracy and Stockton in San Joaquin County

Pop: 30,700 (2022)

Incorporated:1989

Major transit intersection: Interstate 5 and CA State Route 120

Top three employers: Tesla, UPS, Army & Air Force Exchange Service



Energy-related opportunities

- Growing electricity load, particularly commercial & industrial sectors
- Central location relative to agriculture, logistics, and shipping hubs
- Interstate transit corridors for EV fast charging; light, medium, and heavy-duty fleets; and other transportation electrification projects

EAST BAY COMMUNITY ENERGY

Timeline: Lathrop's EBCE Membership

March 2023	July 2023	Aug 2023	Sept 2023	By Dec 2023	2024	2025
EBCE staff invited to present to City Council	City Council votes to join EBCE	EBCE conducts analysis	EBCE Board considers including Lathrop	EBCE updates Imp. Plan for CPUC cert	Community Outreach (with new name and brand)	EBCE enrolls new customers

EAST BAY COMMUNITY ENERGY

Lathrop Quantitative Analysis: Summary

Notable features:

- Lathrop is similar in size to Albany (number of accounts) and Emeryville (citywide load)
- Higher percentage of large commercial & industrial accounts (those with E19/E20 rate classifications)
- Lathrop Irrigation District (LID) serves customers of the River Islands housing development

Parameters of analysis:

- Based on current EBCE overhead costs and 10-year average energy market values/forecasts;
- Assumes 7% account opt out rate (slightly above EBCE's current service area-wide opt out rate)
- Applies EBCE's 2023 rates from 2023-24 budget development
- Data excludes ineligible loads (e.g., Irrigation District and Direct Access customers);
- Applies 2022 PG&E load data for Lathrop (the most recent available)

Lathrop Quantitative Analysis: Summary

- Financial 'Stress Test' measures impact of two key cost variables:

  1) Wholesale energy market prices; and **2)** Power Charge Indifference Adjustment (PCIA)

- Routinely performed by EBCE staff for budget development & power procurement modeling

	Lathrop 2022	EBCE 2022	EBCE w/Lathrop and Stockton 2025
Accounts	7,300	642,400	766,000
Annual Load *(GWh/yr)*	184	6,552	8,220
Peak Load *(MW)*	49	1,636	2,237
Net Position %	+1.6%	+14.5%	+8% (+0.9% specifically due to Lathrop)
Net Position $	$1.77M	$109.99M	$197.99M

EAST BAY COMMUNITY ENERGY

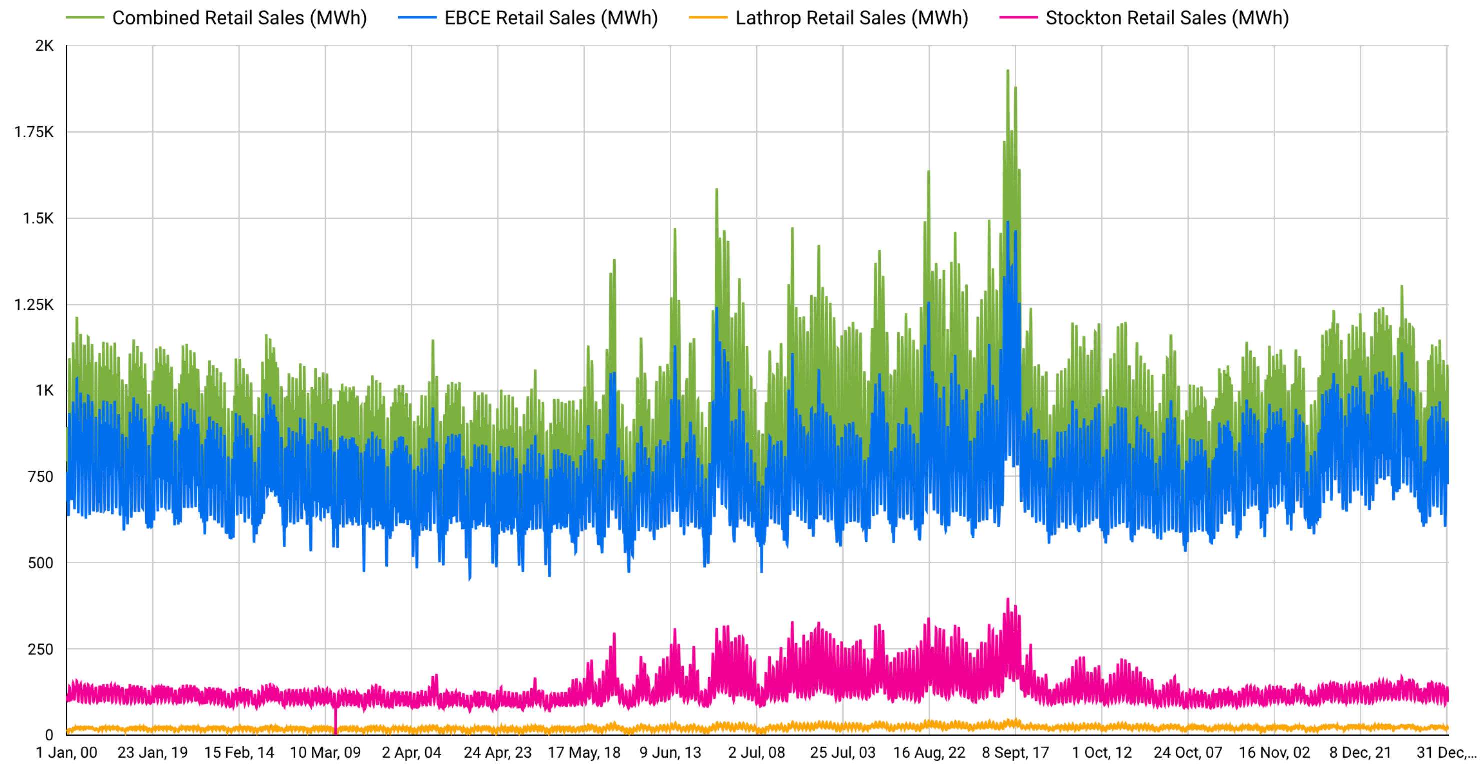
Summary Data

	Customer Count	Annual Load (GWh)	Peak Load (Wholesale MW)	Peak Date & Time (Hour Starting)
EBCE	641,776	6,552	1,636	2022-09-06 16:00
Stockton	111,740	1,154	438	2022-09-06 16:00
Lathrop	7,339	184	49	2022-09-06 17:00
Combined	760,855	7,890	2,120	2022-09-06 16:00

Rate Class	EBCE		Stockton		Lathrop		Combined	
	2022 MWh	%	2022 MWh	%	2022 MWh	%	2022 MWh	%
A1	945,379	14.4%	138,682	12.0%	10,212	5.5%	1,094,273	13.9%
A10	1,035,366	15.8%	159,405	13.8%	19,441	10.6%	1,214,213	15.4%
AGR	49,044	0.7%	1,462	0.1%	682	0.4%	51,189	0.6%
E19	1,316,623	20.1%	168,757	14.6%	55,779	30.3%	1,541,159	19.5%
E20	541,679	8.3%	75,230	6.5%	54,487	29.6%	671,396	8.5%
RES	2,615,021	39.9%	609,383	52.8%	42,344	23.0%	3,266,747	41.4%
LS	41,839	0.6%	97	0.0%	1,157	0.6%	43,092	0.5%
TC	7,070	0.1%	804	0.1%	134	0.1%	8,008	0.1%
Total	**6,552,021**	**100%**	**1,153,821**	**100%**	**184,237**	**100%**	**7,890,078**	**100%**

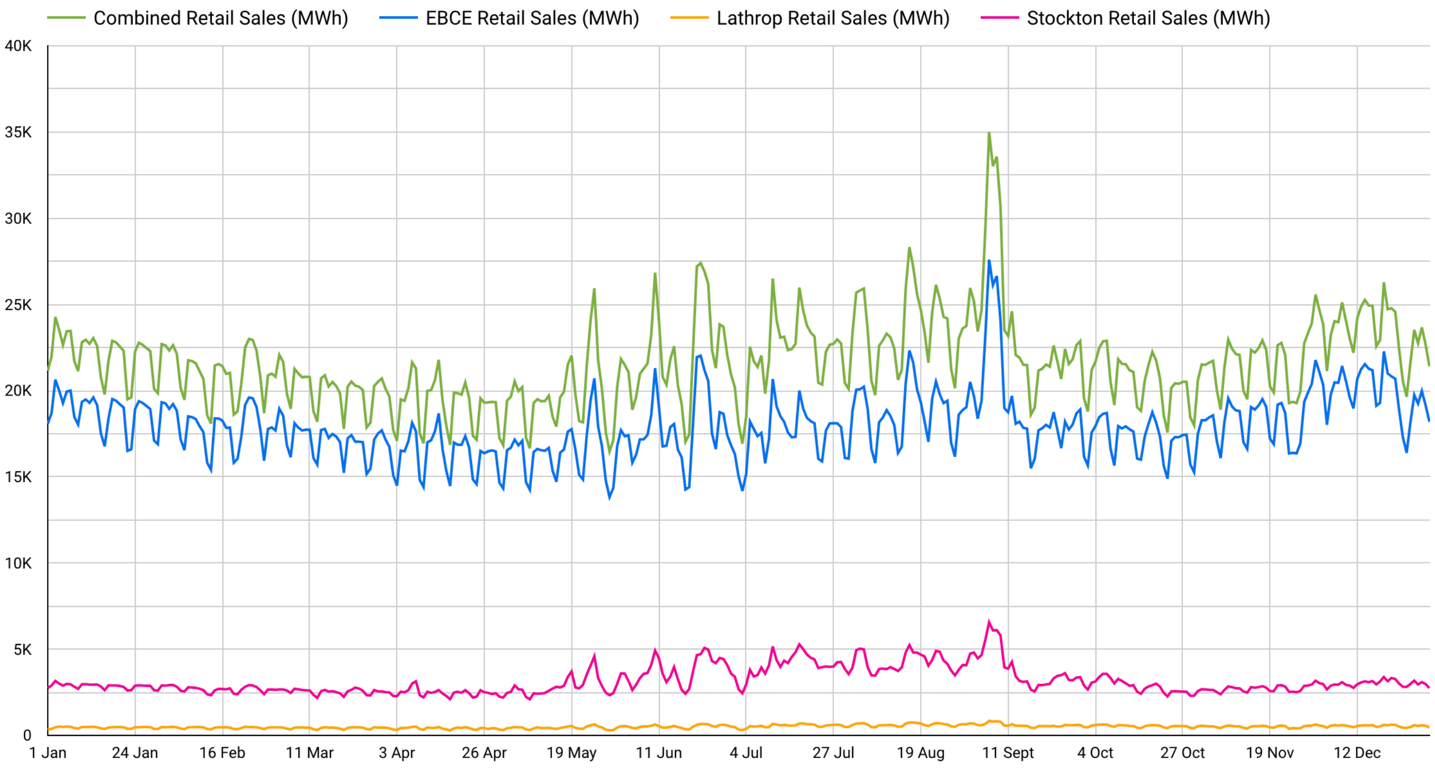
EAST BAY COMMUNITY ENERGY

2022 Hourly Load



EAST BAY COMMUNITY ENERGY

2022 Daily Load



EAST BAY COMMUNITY ENERGY

Qualitative Considerations

- Diversity, Equity, and Inclusion
- Environmental Justice
- Local Programs
- Legislative and Political Influence
- CCA Proliferation, Public Power, Energy Democracy

EAST BAY COMMUNITY ENERGY

Thank You!

Questions? Give us a call:

1-833-699-EBCE (3223)

@PoweredbyEBCE

customer-support@ebce.org

Español
ebce.org/es

中文
ebce.org/cn

Additional Slides

EAST BAY COMMUNITY ENERGY

City of Lathrop: Key JPA Membership Milestones

1. **March 13, 2023**: EBCE staff invited to present informational item to City Council
   - City authorizes EBCE to access citywide PG&E load data
2. **May 2023**: PG&E provides citywide load data to EBCE
3. **July 10, 2023**: City Council unanimously passes Resolution and ordinance to join EBCE
4. **August 14, 2023**: City Council unanimously passes second reading (required by State law) of ordinance to join EBCE

Steps to Joining EBCE

1. Meetings with City staff/elected officials
2. 2-3 presentations to the City Council & Council considers joining JPA
3. EBCE staff conducts quantitative analysis
4. EBCE Board & Community Advisory Committee review analysis and Board considers including new community
5. If Board Approves, EBCE updates JPA and files amended Implementation Plan with the CPUC <u>before 12/31/23</u>

<u>2024</u>: Community outreach in new community

<u>2025</u>: EBCE enrolls customers in new community

CAC Item C9

Staff Report Item 12

TO: East Bay Community Energy Board of Directors

FROM: Annie Henderson, VP Marketing & Account Services
Theresa McDermit, Head of Brand

SUBJECT: **Update on Ava Community Energy Visual Identity and Soft Launch Timeline**

DATE: September 20, 2023

Recommendation

Receive an update on the visual identity and plans for the soft launch of Ava Community Energy

Background and Discussion

Background

In recent years, EBCE has dramatically increased its focus on actively promoting and enabling decarbonization and efficiency initiatives while maintaining its ongoing commitment to the delivery of clean power at low prices. Since early 2022, staff have led an effort to define and articulate an updated brand strategy in support of this broadening mandate. As a result of the strategy, a resolution was approved at the June 2023 Board Meeting to transition the name of the agency to Ava Community Energy starting October 2023 or as determined by direction of the CEO.

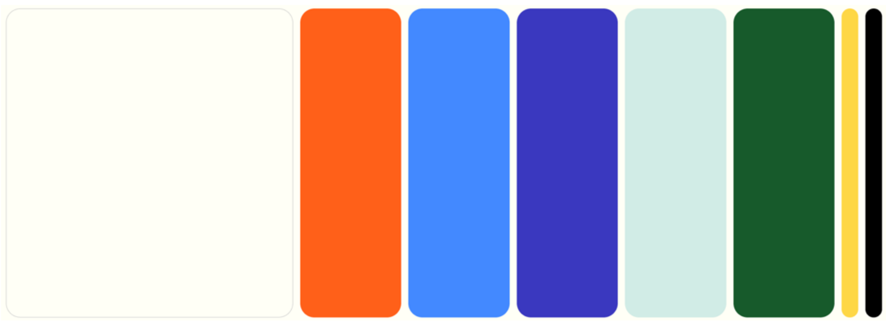
Visual Identity

The brandmark for Ava Community Energy signals our clarity and optimism as a guide for the energy transition and orchestrator of innovative solutions. Its construction evokes the convergence of a community around a shared direction, in addition to making an iconic statement. The color palette was selected to stand out in our category while remaining approachable and friendly, as well as gender neutral.

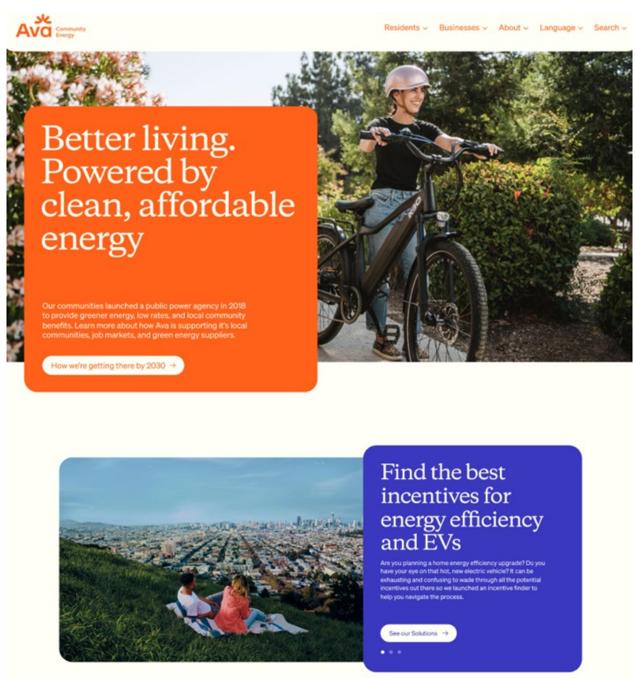
Brandmark

Ava Community Energy

Color Palette



Website Mock-Up



Launch Timeline

We plan to introduce the Ava brand in two phases. We'll adopt the Ava brand in late October (our "soft" launch; scheduled to begin Oct. 24). Between October and the end of the calendar year, we'll work to ensure the brand is applied across all our touchpoints and those of our partners. In early 2024, we'll commence the main launch of the brand with proactive paid advertising and public relations campaigns designed to inform and engage our constituents. Below is a list of some key activities by phase of our launch:

Pre-launch

- **Customer communication** teaser within the Power Content Label mailer

Phase 1 / Soft-launch

- **Website** "reskinned" with Ava branding; language update; URL becomes avaenergy.org
- Employee and other public-facing email **addresses** migrated to @avaenergy.org
- **Call center** scripts and IVR refers to Ava Community Energy
- Core **registrations and relationship documents** required to do business under our new name (e.g. bank accounts, PG&E forms, etc.)
- Adopt Ava **templates**: powerpoint, email, social media, board memos, etc.
- **Municipal partner websites** updated
- EBCE staff will provide local municipal staff with resources for the soft launch by the end of September.

Phase 2 / Main Launch

- Paid **advertising and proactive PR** to engage and inform our constituents

Official Name Change

Staff is working with legal counsel to determine the appropriate way to do business under the name Ava Community Energy. We are investigating the possible use of a ficticious business name and/or an amendment to the Joint Powers Agreement. For reference, both Central Coast Community Energy and Marin Clean Energy did a JPA amendment which did not require member jurisdictions to resign the document or take other local action.

Fiscal Impact

Funding for all re-branding activities was included in the FY23/24 budget

Committee Recommendation

The Brand Ad Hoc Committees of the Board and Community Advisory Committee were asked to identify any critical red flags on the logo design. There is a Marketing, Regulatory, and Legislative Subcommittee meeting in October. At that meeting, staff will provide any updates to the timeline for soft launch and preview of the plan for full launch in January.

EBCE Public Comment received for 9/18/23 Community Advisory Committee Meeting

Letter #	Name	Date
1	Jessica Tovar	9/18/2023
2	Tom Kelly	9/15/2023
3	Tim Frank	9/18/2023

Jessica Tovar
339 15th St Suite 208
Oakland, CA 94612
415-766-7766

Dear East Bay Community Energy Board of Directors,

With the formation of East Bay Community Energy (EBCE) agency in 2016, the joint powers succeeded in providing their constituent territories with a public alternative to investor-owned energy procurement with the explicit intent to promote and provide local, clean energy resources that are more reliable, resilient and affordable *and* to do so centering equity in workforce development, rates, distributed energy resources etc. However, the agency's success in fulfilling its mandate can only be evaluated through thorough accountability to the public it serves. In turn, community accountability is only possible insofar as the agency is transparent to the public about its decision making, business partnerships, programs etc.

Several issues of transparency and inequity have continued at East Bay Community Energy in the past years. We ask that these issues be dealt with promptly in the ways suggested and that this enumeration of concerns be used as guidance for how the board can and should hold the staff accountable to transparent and equitable practices.

1. Performance data on the metrics have not been provided yet the 2018 Local Development Business Plan *Clear and Transparent Reporting* section states: "A clear and cogent set of metrics efficiently reported over time is more effective than an overly complex reporting system that creates undue burden on EBCE staff and confusion among community stakeholders". Most pressing, given the active Request for Proposals (RFP) on phase 2 of the municipal critical facilities is lack of a jobs report and the missing language on workforce standards in theRFP. We suggest the board take this concern up at the next board meeting to adopt agency wide standards.

2. The resilience and virtual power plant program that facilitates microgrid development within the service territory needs to work more closely with communities in order to bundle the benefits of resilience and procurement needs. This pertains to both community-facing municipal critical facilities and community based organizations (CBO). With respect to the former, we ask that EBCE clearly designate the division of funds between community facing and non-community facing resilient municipal facilities and commit to working with CBOs to identify which locations are best suited to provide emergency resilience services to the public.

Regarding the latter, while the 2023-2024 budget states that EBCE does not have the resources to include CBO sponsored sites into the community resilience program, there is $14.75 million of currently unallocated funds in the budget which should be allocated to including CBOs in the program. East Bay Clean Power Alliance acknowledges that $2 million has been dedicated to provide technical assistance to CBOs hoping to access microgrid and resilience funds, however, there is no need for this support to be restricted to technical assistance. Rather, this $14.75 million can support leveraging federal and state funding for CBOs to be more directly incorporated into the virtual power plant, which also further reduces EBCE procurement needs. In addition, the EBCE surplus funds have in total almost $100 million. While we understand the need for some rainy day funds, $100 million in reserve account funding for a public agency is unnecessary compared to the urgency of CBO led resilience programs to serve communities vulnerable to power shut offs and unforeseen crises. We also ask for the “streamlined process” for CBOs to receive technical assistance be released as soon as possible.

3. East Bay Clean Power Alliance acknowledges the long-anticipated RFP for Community Innovation Grants. We appreciate that $300,000 for a 3-year project, makes the grant a significant effort. However, it is concerning that the very first grant in this round has become a “community *investment* grant” focusing on education around induction cooktops. Restricting the goals of the grant to “education and awareness” reduces the scope of benefits organizations could deliver, particularly to low income communities of color. Those communities will need support for replacing gas ranges with expensive induction ranges, which may also require even more expensive electrical panel upgrades alongside education. While “lack of information and familiarity” and “emotional connection” with gas may be contributing factors, slow adoption of induction appliances, particularly in equity priority communities cannot reasonably be attributed to lack of information, when such significant financial impediments are present.

The language of this RFP is not representative of the intent of community innovation grants, which as laid out in the Local Development Business Plan, are intended to “deliver social and environmental benefits” and prioritize disadvantaged communities. Furthermore, the solicitation should be in the form of an accessible community grant application. The restrictions on the one hand to education and awareness and secondly to induction cooktops do not provide meaningful benefits. Furthermore the language of the RFP makes it inaccessible to smaller community based organizations despite their real ties to communities that may be more effective in the first place and in need of the funds. This also furthers a systemic barrier where large non-profits with existing programs, funds and development capacity can easily undercut funding opportunities from small CBOs. The future community grants application needs to be written with more of a lens towards equity and accessibility for small CBOs and the communities they serve. We recommend the following changes for future community innovation grants.

1. Grant applications should be directed towards a broader scope of issues, for example the full range of building decarbonization rather than one limited technology.
2. Grant applications should allow for and encourage small organizations serving a part of the service territory to apply for a portion of the full grant. This enables a far more tailored approach to community outreach. As such, smaller grants at $50,000 are crucial in addition to larger $100,000 for the next three years.
3. Community Innovation Grants should not be limited to education and awareness but should fund projects that also leverage funding and facilitate access to new technologies. The Induction Cooktop Lending Program and giveaways alone are insufficient for meaningful health or energy benefits.
4. Community input on the grant application design and process should be implemented.
5. A subcommittee made up of Community Advisory Committee members and Board members should field applications and make the grant awards. As they had in 2019.
6. Funding for community innovation grants has not been issued since 2019 and was reinstated in June of 2022, therefore EBCE should release grant opportunities as soon as possible as access to the funds is overdue.

4. After having avoided a costly misappropriation of EBCE funds in a $15 million charity gift to UCSF Benioff Children’s Hospital, direct information about the reallocation of these funds has not been provided. In June at the agency’s board meeting, staff indicated that they had identified a health care provider with research capabilities, had secured verbal agreement to support the health care partnership, had identified several

non-profit partners to manage health care partnerships and were hiring a building electrification channel manager. None of these secured partnerships were disclosed. Especially given the lack of transparency and illegal nature of this $15M gift of ratepayer funds, it is of the utmost importance that EBCE staff provide clarity on who they will be partnering with, and provide clarity on geographic locations and exact numbers and types of stoves provided.

These four primary concerns of transparency and equity at East Bay Community Energy are indicative of a longer history at the agency. Public accountability through verifiable metrics and feedback, access to resources for disadvantaged communities, and long term investment in communities through workforce standards and collaborations with CBOs have been systematically deprioritized. The very formation of East Bay Community Energy was a community effort, we at East Bay Clean Power Alliance hope to see this new board support the agency in living up to its mandate.

Sincerely,

Jessica Guadalupe Tovar, East Bay Clean Power Alliance

Gmail

Adrian Bankhead <abankhead@ebce.org>

EBCE emissions associated with EV charging vs. PG&E

1 message

Tom Kelly <tkelly@kyotousa.org> Mon, Sep 18, 2023 at 1:58 PM
To: Anne Olivia Eldred <anneolivia.eldred@gmail.com>
Cc: Adrian Bankhead <abankhead@ebce.org>

Anne Olivia,

Attached is a comparison of GHG emissions associated with charging your EV with Bright Choice vs. PG&E. Once again, EBCE falls far short of its only competition and adds to the growing climate calamity the planet is facing. Those who switch to a EV to fight climate change and also receive Bright Choice are actually making the problem worse rather than better. Let's do something about it!

Tom Kelly

Compparing PG&E and EBCE on EV charging emissions.xlsx
11K

Bright Choice - PG&E Comparison: EV Charging

CO2 released from gasoline				
Burning gasoline	8,887	grams CO2/gallon	https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle	
ICE vehicle fuel economy	30	MPG	Fleet average - 25.4 MPG in 2021	
Gasoline vehicle emissions	296	grams CO2/mile		
Emissions on the CA electric grid	282	grams CO2/kWh	https://app.electricitymaps.com/map	Average in California for 12 months - September 2022 to August 2023
EV charging on CA electric grid (3.7 miles/kWh)	80	grams CO2/mile		
PG&E data (2021)				
2021 PG&E emissions	96	lbs. CO2/MWh	2022 Power Content Label is not yet available, but is likely to be 50% less than 2021	
EV charging on PG&E electricity	44	grams CO2/kWh		
EV charging on PG&E electricty (3.7 miles/kWh)	12	grams CO2/mile		
EBCE data 2022)				
2022 EBCE Bright Choice emissions	496	lbs. CO2/MWh		
EV charging on EBCE's Bright Choice	225	grams CO2/kWh		
EV charging on EBCE's Bright Choice (3.7 miles/kWh)	61	grams CO2/mile		

Proposed by CCA Workforce and EJ Alliance
https://action.greencal.org/action/wej

September 18, 2023

DRAFT: East Bay Community Energy (EBCE) Workforce, Environmental, and Environmental Justice Standards for Clean Energy Project Selection Policy

PREAMBLE

WHEREAS, EBCE, as a Community Choice Aggregation, is a mission-driven public agency, collectively financed by constituent public ratepayers, with an obligation and opportunity to support and protect workers and the communities hosting EBCE's clean energy projects.

WHEREAS, EBCE, a mission-driven public agency committed to diversity, equity, and inclusion, has the opportunity to align with and support the values and mission of high-road union construction trade labor and environmental justice organizations striving to create sustainable and equitable communities.

WHEREAS, Central Coast Community Energy (3CE), a peer CCA to EBCE, adopted similar standards to the recommended standards below in June 2023 after extensive deliberation by its Board of Directors and Citizens Advisory Committee,

WHEREAS, 3CE'S procurement standards serve as a foundation for best practices and build on similar standards adopted earlier by Peninsula Clean Energy and the San Francisco Public Utilities Commission (CleanPowerSF)

WHEREAS x% of customers in existing service territory are CARE, FERA, or Medical baseline customers, and x% in San Joaquin Counties (staff support requested to advise on these values).

WHEREAS, rate payer dollars can create local benefits through the creation of jobs and supporting local, small local, and emerging businesses in our service territory by keeping dollars in circulation

WHEREAS, EBCE's Joint Powers Agency Agreement, dated effective November 1, 2016, as amended by Resolution No. 2018-23 dated June 20, 2018, declares the agency's purpose as follows:

- Provide electricity rates that are lower or competitive with those offered by PG&E for similar products;
- Develop an electric supply portfolio with a lower greenhouse gas (GHG) intensity than PG&E, and **one that supports the achievement of the parties' greenhouse gas reduction goals** and the comparable goals of all participating jurisdictions;
- Establish an energy portfolio that **prioritizes the use and development of local renewable resources** and minimizes the use of unbundled renewable energy credits;
- Promote an energy portfolio that **incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals**;
- **Demonstrate quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);**
- **Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California.** The Authority, as a leader in the shift to a clean energy, commits to ensuring it will **take steps to minimize any adverse impacts to these workers to ensure a "just transition" to the new clean energy economy;**
- Deliver clean energy programs and projects **using a stable, skilled workforce through such mechanisms as project labor agreements or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;**
- Promote personal and community ownership of renewable resources, spurring **equitable economic development and increased resilience, especially in low income communities;**
- Provide and manage lower cost energy supplies in a manner that **provides cost savings to low-income households and promotes public health in areas impacted by energy production**; and
- Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through **adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize and providing appropriate wages and benefits.**

THEREFORE, BE IT RESOLVED THAT,

In support of competitive, clean, and renewable power supply, as well as the development of a local and diverse workforce, the Governing Board of East Bay Community Energy (EBCE) shall adopt the following **Workforce, Environmental, and Environmental Justice Standards for Clean Energy Project Selection Policy** asserting a preference for enhanced workforce, environmental, and environmental justice standards for all EBCE's clean energy programs and projects.

I. DEFINITIONS

1. **Regulatory Value:** The project's anticipated ability to satisfy EBCE's regulatory compliance requirements, such as Resource Adequacy, Renewable Portfolio Standard, integrated resource planning, and other binding orders or directives received from regulatory bodies.

2. **Market Value**: The project's projected revenues across all relevant day-ahead, real-time and ancillary markets. Market Value shall also assess a project's ability to manage, shift, or arbitrage existing EBCE generation to maximize revenue and renewable energy generation on behalf of EBCE and its customers.

3. **Counterparty Risk:** The risk that a counterparty will fail to perform, or adequately remedy, its obligations. Counterparty Risk is inclusive of Development Risk.

4. **Development Risk:** The risk that the project is unable to obtain interconnection, deliverability, site control, entitlements, financing, or other necessary development milestones required to deliver the project on or ahead of the anticipated online date.

5. **Energy Offtake Agreement:** Includes Power Purchase Agreements, Energy Storage Agreements, Resource Adequacy Only Agreements, or other energy-related products where EBCE does not own, develop, or construct the generation or storage facility. Instead, EBCE's participation in the Project is limited to receiving energy and any applicable attributes at a set price and term.

6. **Journeyperson:** Is a worker who either:
    1. Graduated from a California state-approved apprenticeship program for the applicable occupation or, when located outside California, approved for federal purposes pursuant to apprenticeship regulations adopted by the Secretary of Labor, or
    2. Has at least as many hours of on-the-job experience in an applicable occupation as would be required to graduate from an apprenticeship

program for the applicable occupation that is approved by the California Division of Apprenticeship Standards.

7. **Local Hire:** A stated preference for project employment opportunities for qualified workers in descending priority:
    1. A resident within the nearest communities in proximity to the project, by radius as reasonably determined on a project-by-project basis;
        a) Additional preference shall be given, where the radius includes a city, town, or census-designated location within EBCE's service territory, to the workers within those portions of the service territory.
    2. A resident within the county where the project is being constructed;
    3. A resident within EBCE's service territory.

8. **Skilled and Trained Workforce:** A Skilled & Trained Workforce consists of all workers performing work in an apprenticeable occupation in the building and construction trades who are either skilled journeypersons or apprentices registered in an apprenticeship program approved by the chief of the Division of Apprenticeship Standards, as defined in Chapter 2.9 (commencing with Section 2600) of Part 1 of Division 2 of the California Public Contract Code.

9. **Targeted Hire Program:** A pipeline program which creates opportunities for Under-Represented Workers to (a) enter Registered Apprenticeship Programs and (b) obtain work hours needed to successfully complete their apprenticeship, through partnering with a Multi-Craft Core Curriculum (MC3) pre-apprenticeship program or programs, or equivalent industry and union-recognized certificated career training and placement program, that recruits, supports, and prepares Under-Represented Workers to succeed in skilled construction trades apprenticeships.

10. **Under-Represented Worker:** A jobseeker who, at the time of hiring or within the last twelve months, satisfies at least one of the following categories::
    1. Experiencing or at risk of homelessness
    2. Being a custodial single parent
    3. Currently receiving public assistance
    4. Lacking a GED or high school diploma
    5. Having been continuously unemployed or underemployed for the past 6 months
    6. Having been emancipated from the foster care system

7. Being a veteran of the United States Military
8. Being a member of a tribal community
9. Having a previous incarcerated or justice involvement history
10. At-Risk Youth: a person 18-24 years old who is disconnected from school and/or work
11. Low income (household income is below the current HUD threshold for Low Income Households in their county of residence)

II. PROJECT SELECTION METHODOLOGY

Projects will be prioritized for selection based on EBCE's evaluation of the criteria set forth below.

A. <u>Contributions to EBCE's 100% Renewable Energy by 2030 Goal</u>

1. Assessment and evaluation of proposed projects' operational performance and market economics to ensure selected projects maximize regulatory and market value to EBCE and its customers.
2. Assessment and evaluation of Counterparty and Development Risk.
3. Avoids unbundled or Category 3 RECs and non-RPS carbon-free attributes

B. <u>Workforce and Local Workforce Development</u>

EBCE is committed to stimulating our local economy through, among other measures, supporting Projects committing to apply prevailing wage rates, supporting participants and/or graduates of apprenticeship and pre-apprenticeship programs, supporting a local Skilled and Trained Workforce, and to achieve EBCE's local and targeted hire objectives.

1. EBCE will prioritize Energy Offtake Agreements where the developer is committed to:
    a. Highest priority projects will commit to:
        i. A multi-trade project labor agreement that incorporates EBCE's Local and Targeted Hire objectives as follows:
            1. A goal of 30% of all project labor hours performed by Local Hires, and;
            2. Participation in a Targeted Hire Program with a goal of 10% of all project hours performed by Under-Represented Worker apprentices.
    b. Medium-priority projects will commit to:
        i. Utilization of a Skilled and Trained Workforce and commitment that construction work will be performed by appropriate Journeypersons and apprentices from a state-approved apprenticeship training program; and
        ii. Utilization of prevailing hourly wage and benefit rates as determined by the California Department of Industrial Relations.

iii. Demonstrated commitment to Local and Targeted Hire, including utilization of a multi-craft core curriculum (MC3) pre-apprenticeship program, or equivalent industry and union-recognized pre-apprenticeship certification, for outreach, preparation, support and referral of Targeted Hires.

c. Low-priority projects would fail to meet II.B.1.a or II.B.1.b above but may demonstrate other commitments to local workforce development.

2. When considering contractors or developers for EBCE-owned energy generation or storage projects requiring a Large Generator Interconnection Agreement from the California Independent System Operator (currently 20MW and above, but subject to change from time to time), EBCE shall commit to:
    a. Negotiate a multi-trade project labor agreement that will incorporate EBCE's local and targeted hire objectives as follows:
        i. A goal of 30% of all project labor hours performed by Local Hires, and;
        ii. Participation in a Targeted Hire Program with a goal of 10% of all project hours performed by Under-Represented Worker apprentices..
3. When considering contractors or developers for EBCE-owned energy generation or storage projects requiring a Small Generator Interconnection Agreement from the California Independent System Operator (currently applies to projects under 20MW, but subject to change from time to time), EBCE will commit to:
    a. Utilization of a Skilled and Trained Workforce and a commitment that construction work will be performed by appropriate Jouneypersons and Apprentices from a state-approved apprenticeship training program.
    b. Utilization of prevailing hourly wage and benefit rates as determined by the California Department of Industrial Relations.
    c. Demonstrated commitment to Local and Targeted Hires.
        i. A goal of 30% of all project labor hours performed by Local Hires while incenting, through a negotiated contract structure, the contractor or developer to achieve a minimum of 60% of all project labor hours performed by Local Hires, and;
        ii. Participation in a Targeted Hire Program with a goal of 10% of all labor hours performed by Under-Represented Worker apprentices, while incenting, through a negotiated contract structure, the contractor or developer to achieve the 10% goal.

C. <u>Innovation</u>

EBCE recognizes that reaching 100% Renewable Energy by 2030 will require significant improvements and innovation in battery technologies, renewable baseload, dispatchable renewable resources, and renewable generation technologies, among other opportunities.

1. EBCE will prioritize projects that accelerate decarbonization, provide local resiliency, provide EBCE a competitive advantage, and/or reduce costs

for EBCE customers while remaining cost competitive with established market alternatives. Innovation will be recognized among projects that:

a. Include new or improved technologies or methodologies with a demonstrated potential feasibility;
b. Achieve scale for existing technologies to benefit EBCE customers; or
c. Reduce or eliminate barriers to adoption of local scaled technologies.

D. <u>Location</u>

EBCE prioritizes projects in the following order:

1. Projects located within EBCE's service territory
2. Projects located within California.
3. Out-of-state projects

E. <u>Environmental Stewardship</u>

EBCE is committed to leading by providing customers with energy that delivers benefits for air, water, and the natural environment while avoiding impacts to important lands, species, and waters.

1. EBCE will prioritize projects that:
   a. Avoid sensitive habitats for any endangered plant or animal species or other environmentally sensitive areas[1] and comply with conservation plans such as the Desert Renewable Energy Conservation Plan (DRECP)[2];
   b. The developer and local land use authority have established an enforceable development agreement which, in part, sets forth measures to mitigate impacts to sensitive habitat or environmentally sensitive area; then
   c. The developer commits to measurable offset efforts within the vicinity of the proposed project.

F. <u>Benefits Accruing to Underserved Communities</u>

EBCE seeks to deliver economic, environmental, and social benefits to the communities that it serves by providing cleaner electricity at competitive rates, developing local resources that drive new investments, and creating increased demand for high-paying jobs. EBCE is committed to helping low-income and environmental justice communities overcome barriers to their access to public investments, resources, education, and information about energy service and policy.

EBCE will prioritize projects that:

1. Invest in low-income and environmental justice communities

[1] Refer to Nature Conservancy's Power of Place West Report (2022).
[2] Refer to Desert Renewable Energy Conservation Plan (2016).

2. Demonstrate contact and collaboration with local community. organizations and stakeholder groups representing a broad diversity of demographics and interests, particularly low income and environmental justice communities, to identify and address benefits and impacts of projects and ensure project benefits are communicated and accessible to the local community.
3. Commit to meaningful engagement[3] with local communities throughout the entitlement and construction processes to identify and address benefits and impacts of projects and ensure project benefits are communicated and accessible to the local community.

III. EVALUATION, SELECTION AND REPORTING

A. EBCE will assess and select project proposals in accordance with this Project Selection Methodology and report detailed results of such assessment at the time of the project approval.

B. EBCE's annual report will compile and report information regarding the impact of the Project Selection Methodology.

IV. CA COMMUNITY POWER

A. EBCE's representative to the CA Community Power Board shall advocate for adoption of a CA Community Power Workforce, Environmental, and Environmental Justice Standards for Clean Energy Project Selection Policy consistent with the terms of this resolution.

B. EBCE's representative to the CA Community Power Board shall advocate to form a public advisory committee, including labor, environmental and equity representatives, to ensure transparency and public engagement in CA Community Power's operations and procurement practices.

[3] Meaningful engagement means implementing five recommendations for best practices from Building a Just Energy Future - A framework for community choice aggregators to power equity and democracy in California, 2020 report by the California Environmental Justice Alliance