MCE Empowering Our Clean Energy Future

CONTRA COSTA | MARIN | NAPA | SOLANO

MARIN COUNTY | NAPA COUNTY | UNINCORPORATED CONTRA COSTA COUNTY | UNINCORPORATED SOLANO COUNTY
BENICIA | CONCORD | DANVILLE | EL CERRITO | FAIRFIELD | HERCULES | LAFAYETTE | MARTINEZ | MORAGA | OAKLEY
PINOLE | PITTSBURG | PLEASANT HILL | RICHMOND | SAN PABLO | SAN RAMON | VALLEJO | WALNUT CREEK

MCE Board of Directors Meeting
Thursday, May 16, 2024
6:30 P.M.

Public comments may be made in person or remotely via the details below.

1125 Tamalpais Avenue, San Rafael, CA 94901 (MCE)
2300 Clayton Road, Suite 1150, Concord, CA 94920 (MCE)
955 School Street, Napa, CA 94559, City Hall Committee Room (City of Napa)
329 Rheem Blvd., Moraga, CA 94556, Moraga Town Hall, Walnut Conference Room, 2nd Floor (Moraga)

Remote Public Meeting Participation
Video Conference: https://zoomto.me/F6Ogt
Phone: Dial (669) 900-9128, Meeting ID: 890 0487 7785, Passcode: 525690

Agenda Page 1 of 2

1. Roll Call/Quorum

2. Board Announcements (Discussion)

3. Public Open Time (Discussion)

4. Report from Chief Executive Officer (Discussion)

5. Consent Calendar (Discussion/Action)
   - C.1 Approval of 3.21.24 Meeting Minutes
   - C.2 Approved Contracts for Energy Update
   - C.3 Member Community Voting Shares Annual Update

6. Board Member Additions to Committees (Discussion/Action)

7. Proposed MCE Load Management Standards Plan (Discussion/Action)

8. Legislative Update (Discussion)

9. Board & Staff Matters (Discussion)

10. Adjourn

The Board may discuss and/or take action on any or all of the items listed on the agenda irrespective of how the items are described.

DISABLED ACCOMMODATION: If you are a person with a disability who requires an accommodation or an alternative format, please contact MCE at (888) 632-3674 or ada-coordinator@mcecleanenergy.org at least 72 hours before the meeting start time to ensure arrangements are made.

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MCE BOARD MEETING MINUTES
Thursday, March 21, 2024
7:00 P.M.

Present:	Eli Beckman, Town of Corte Madera Kari Birdseye, City of Benicia Monica Brown, County of Solano Barbara Coler, Town of Fairfax Cindy Darling, City of Walnut Creek Alexis Fineman, Town of San Anselmo David Fong, Town of Danville John Gioia, Contra Costa County Ryan Gregory, The County of Napa and Four Napa Cities/Town (American Canyon, Calistoga, St. Helena, and Town of Yountville) Janelle Kellman, City of Sausalito J.R. Matulac, City of Vallejo Eduardo Martinez, City of Richmond Aaron Meadows, City of Oakley John McCormick, Alternate, City of Lafayette Devin Murphy, City of Pinole Laura Nakamura, City of Concord Elizabeth Pabon-Alvarado, City of San Pablo Beth Painter, City of Napa Gabe Paulson, City of Larkspur Max Perrey, City of Mill Valley Gabriel Quinto, City of El Cerrito Katie Rice, County of Marin Matt Rinn, City of Pleasant Hill Holli Thier, Town of Tiburon Sally Wilkinson, City of Belvedere Brianne Zorn, City of Martinez
Absent:	Maika Llorens Gulati, City of San Rafael Kerry Hillis, Town of Moraga C. William Kircher, Town of Ross Scott Perkins, City of San Ramon Shanelle Scales-Preston, City of Pittsburg Susan Wernick, City of Novato K. Patrice Williams, City of Fairfield
Staff & Others:	Jesica Brooks, Board Clerk Vicken Kasarjian, COO Tanya Lomas, Internal Operations Coordinator

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Catalina Murphy, General Counsel
Zae Perrin, Director of Customer Operations
Garth Salisbury, Chief Financial Officer & Treasurer
Enyonam Senyo-Mensah, Office Manager
Daniel Settlemyer, Internal Operations Coordinator
Maira Strauss, Manager of Finance
Jamie Tuckey, Chief of Staff
Dawn Weisz, CEO

1. Roll Call
   Acting Chair Quinto called the regular meeting to order at 6:42 p.m. with quorum established by roll call.

2. Board Announcements (Discussion)
   There were none.

3. Public Open Time (Discussion)
   Acting Chair Quinto opened the public comment period and comments were made by David Moller.

4. Report from Chief Executive Officer (Discussion)
   CEO Dawn Weisz introduced this item and addressed questions from Board members.

   Acting Chair Quinto opened the public comment period and there were no comments.

5. Consent Calendar (Discussion/Action)
   C.1 Approval of 2.15.24 Meeting Minutes
   C.2 Approved Contracts for Energy Update
   C.3 Proposed First Amendment to Second Agreement with Energy Solutions

   Acting Chair Quinto opened the public comment period and there were no comments.

Action 1: It was M/S/C (Beckman/Thier) to **approve Consent Calendar items C.2 and C.3.** Motion carried by unanimous roll call vote. (Absent: Directors Gulati, Hillis, Kircher, Perkins, Scales-Preston, Wernick, and Williams).

Action 2: It was M/S/C (Beckman/Paulson) to **approve Consent Calendar items C.1.** Motion carried by roll call vote. (Abstained: Thier Absent: Directors Gulati, Hillis, Kircher, Perkins, Scales-Preston, Wernick, and Williams).

6. Proposed Fiscal Year 2024/25 Budget (Discussion/Action)
   Garth Salisbury, Chief Financial Officer & Treasurer, and Maira Strauss, Manager of Finance, introduced this item and addressed questions from Board members.

   Acting Chair Quinto opened the public comment period and comments were made by Ken Strong.

Action: It was M/S/C (Murphy/Rinn) to: 1. Approve the proposed Fiscal Year 2024/25 budgets. 2. Approve the Targeted Cost Relief Program with an allocation of $5,000,000. Motion carried by unanimous roll call vote. (Absent: Directors Gulati, Hillis, Kircher, Perkins, Scales-Preston, Wernick, and Williams).

7. Fiscal Year 2023/24 Update, Projections, and Discussion of Proposed Transfers and Deferrals (Discussion)
   Garth Salisbury, Chief Financial Officer & Treasurer, and Maira Strauss, Manager of Finance, introduced this item and addressed questions from Board members.

   Acting Chair Quinto opened the public comment period and comments were made by Dan Segedin, Ken Strong, David Moller, Fred Bialy, and Bonnie Hamilton.

Action: No action required.

11. Board & Staff Matters (Discussion)
    There were none.

12. Adjournment
    Acting Chair Quinto adjourned the meeting at 9:33 p.m. to the next scheduled Board Meeting on April 18, 2024.

_____
Gabriel Quinto, Acting Chair

Attest:

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_____

Dawn Weisz, Secretary

May 16, 2024

TO: MCE Board of Directors

FROM: Stephen Mariani, Senior Power Procurement Manager

RE: Approved Contracts for Energy Update (Agenda Item #05 C.2)

Dear Board Members:

SUMMARY:
This report summarizes contracts for energy procurement entered into by the Chief Executive Officer or her delegate and, if applicable, the Chair of the Technical Committee, since the last regular Board meeting in March. This summary is provided to your Board for information purposes only and no action is needed.

Review of Procurement Authorities

In November 2020, your Board adopted Resolution 2020-04 which included the following provisions:

> *The CEO and Technical Committee Chair, jointly, are hereby authorized, after consultation with the appropriate Committee of the Board of Directors, to approve and execute contracts for Energy Procurement for terms of less than or equal to five years. The CEO shall timely report to the Board of Directors all such executed contracts.*
>
> *The CEO is authorized to approve and execute contracts for Energy Procurement for terms of less than or equal to 12 months, which the CEO shall timely report to the Board of Directors.*

The CEO is required to report all such contracts and agreements to the MCE Board of Directors on a regular basis.

Item #	*Month of Execution*	*Purpose*	*Average Annual Contract Amount*	*Contract Term*
1	March 2024	Purchase of Renewable Energy	$9,375,000	Under 1 Year
2	March 2024	Purchase of Resource Adequacy	$35,000	Under 1 Year
3	March 2024	Sale of Resource Adequacy	$2,250,000	Under 1 Year
4	April 2024	Sale of Resource Adequacy	$660,000	Under 1 Year
5	April 2024	Sale of Resource Adequacy	$440,000	Under 1 Year
6	April 2024	Purchase of System Energy (Hedge)	$1,839,768	1-5 Years
7	April 2024	Purchase of System Energy (Hedge)	$5,595,610	1-5 Years
8	April 2024	Purchase of System Energy (Hedge)	$939,803	Under 1 Year
9	April 2024	Purchase of System Energy (Hedge)	$5,503,113	1-5 Years
10	April 2024	Purchase of System Energy (Hedge)	$4,986,369	Under 1 Year
11	April 2024	Purchase of Resource Adequacy (Imports)	$5,566,260	Under 1 Year
12	April 2024	Purchase of Resource Adequacy (Imports)	$100,000	Under 1 Year
13	April 2024	Purchase of Resource Adequacy (Import Rights)	$18,000	Under 1 Year

Contract Approval Process: Energy procurement is governed by MCE's Energy Risk Management Policy as well as Board Resolutions 2020-04 and 2018-08. The Energy Risk Management Policy (Policy) has been developed to help ensure that MCE achieves its mission and adheres to its procurement policies established by the MCE Board of Directors (Board), power supply and related contract commitments, good utility practice, and all applicable laws and regulations. The Board Resolutions direct the CEO to sign energy contracts up to and including 12 months in length.

The evaluation of every new energy contract is based upon how to best fill MCE's open position. Factors such as volume, notional value, type of product, price, term, collateral threshold and posting, and payment are all considered before execution of the agreement.

After evaluation and prior to finalizing any energy contract for execution, an approval matrix is implemented whereby the draft contract is routed to key support staff and consultants for review, input, and approval. Typically, contracts are routed for commercial, technical, legal, and financial approval, and are then typically routed through the Chief Operating Officer for approval prior to execution. The table below is an

example of MCE staff and consultants who may be assigned to review and consider approval prior to the execution of a new energy contract or agreement.

Review Owner	*Review Category*
Vidhi Chawla (MCE, Vice President of Power Resources)	Procurement/Commercial
John Dalessi (Pacific Energy Advisors)	Technical Review
Steve Hall (Hall Energy Law)	Legal
Nathaniel Malcolm (MCE, Senior Policy Counsel)	Legal/CPUC Compliance
Garth Salisbury (MCE, Chief Financial Officer & Treasurer)	Credit/Financial
Vicken Kasarjian (MCE, Chief Operating Officer)	Executive

Fiscal Impacts: Expenses and revenue associated with these Contracts and Agreements that are expected to occur during FY 2024/25 are within the FY 2024/25 Operating Fund Budget. Expenses and revenue associated with future years will be incorporated into budget planning as appropriate.

Recommendation: Information only. No action required.

May 16, 2024

TO: MCE Board of Directors

FROM: Catalina Murphy, General Counsel

RE: Member Community Voting Shares Update (Agenda Item #05 C.3)

ATTACHMENTS:
A. MCE Joint Powers Agreement
B. Exhibit C to the MCE Joint Powers Agreement: Annual Energy Use
C. Exhibit D to the MCE Joint Powers Agreement: Voting Shares

Dear Board Members:

Summary:
Consistent with the MCE Joint Powers Agreement ("JPA"), attached hereto as Attachment A, your Board is attributed voting shares based on current MCE membership as well as the respective annual energy use of each member community. Such voting shares are determined via a two-step process, which considers the following factors: 1) the current number of MCE member communities (Section 4.9.2.1 of the JPA); and 2) the annual energy use of each member community relative to MCE's total annual energy, which is the sum of all member communities' annual energy use (Section 4.9.2.2 of the JPA). Each factor is expressed as a ratio with a weight of 50% ascribed.

The first factor (total number of MCE member communities) results in an equal voting share for each MCE member community: this fractional voting share is currently 1.32% for each MCE member community, derived through the following calculation: 1/38 * 50% = 1.32%. The second factor is derived by determining the ratio of each member community's annual energy use to MCE's total annual energy; the resultant ratio is also multiplied by 50%. For example, if annual energy use within the unincorporated County of Napa is 293 GWh and MCE's total annual energy is 5,729 GWh, the County of Napa's load-related voting share is 2.56%: 293/5,729 * 50% = 2.56%. As a result, the County of Napa's total MCE voting share would be 3.88% (2.56% + 1.32%). The voting share will vary by each member community.

MCE's voting shares are to be updated annually before March 1st of each year, as per Section 4.9.2.2 of the JPA, to reflect changes in MCE's total annual energy as well as changes and/or additions to MCE's member communities. However, due to data availability, MCE's voting shares update was delayed to this May Board meeting.

At this time, MCE has the necessary data to update its total annual energy, the annual energy use of each member community, and the voting shares calculation. Accordingly, MCE has prepared revised Exhibits C and D to the JPA, which reflect the results of these updated calculations. Exhibit C displays each member community's annual energy use as well as MCE's total annual energy. Exhibit D displays key elements of MCE's voting shares calculations, consistent with Sections 4.9.2.1 and 4.9.2.2 of the JPA, and reflects the voting share attributable to each member community.

Pursuant to Section 4.9.2.2 of the JPA, Exhibit C is to be adjusted annually to properly update the voting shares. As per Section 4.9.2.3 of the JPA, Exhibit D may be updated to reflect revised annual energy use amounts and any changes in the parties to the JPA without amending the JPA, provided the Board is given a copy of the updated Exhibit D. Therefore, MCE staff is providing a copy of the updated Exhibit D which reflects the revised and updated voting shares of the current MCE member communities. The updated Exhibits C and D referenced in this staff report will replace the existing Exhibits C and D within the JPA.

Fiscal Impacts:

None.

Recommendation:

Approve the updated Exhibit C and Exhibit D to the MCE Joint Powers Agreement.

Marin Energy Authority
- Joint Powers Agreement -

Effective December 19, 2008
As amended by Amendment No. 1 dated December 3, 2009
As further amended by Amendment No. 2 dated March 4, 2010
As further amended by Amendment No. 3 dated May 6, 2010
As further amended by Amendment No. 4 dated December 1, 2011
As further amended by Amendment No. 5 dated July 5, 2012
As further amended by Amendment No. 6 dated September 5, 2013
As further amended by Amendment No. 7 dated December 5, 2013
As further amended by Amendment No. 8 dated September 4, 2014
As further amended by Amendment No. 9 dated December 4, 2014
As further amended by Amendment No. 10 dated April 21, 2016 As further amended by Amendment No. 11 dated May 19, 2016
As further amended by Amendment No. 12 dated July 20, 2017
As further amended by Amendment No. 13 dated October 18, 2018
As further amended by Amendment No. 14 dated November 21, 2019
As further amended by Amendment No. 15 dated November 19, 2020
As further amended by Amendment No. 16 dated November 16, 2023

Among the Following Parties:
City of American Canyon
City of Belvedere
City of Benicia
City of Calistoga
City of Concord
Town of Corte Madera
Town of Danville
City of El Cerrito
Town of Fairfax
City of Fairfield
City of Hercules
City of Lafayette
City of Larkspur
City of Martinez
Town of Moraga
City of Mill Valley
City of Napa
City of Novato
City of Oakley
City of Pinole

City of Pittsburg
City of Pleasant Hill
City of Richmond
Town of Ross
Town of San Anselmo
City of San Pablo
City of San Rafael
City of San Ramon
City of Sausalito
City of St. Helena
Town of Tiburon
City of Vallejo
City of Walnut Creek
Town of Yountville
County of Contra Costa
County of Marin
County of Napa
County of Solano

MARIN ENERGY AUTHORITY
JOINT POWERS AGREEMENT

This **Joint Powers Agreement** ("Agreement"), effective as of December 19, 2008, 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 B ("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 emissions.

3. The purposes for the Initial Participants (as such term is defined in Section 2.2 below) entering into this Agreement include addressing climate change by reducing energy related greenhouse gas emissions and securing energy supply and price stability, energy efficiencies and local economic benefits. 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 solar and wind energy production.

4. The Parties desire to establish a separate public agency, known as the Marin 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 Community Choice Aggregation, an electric service enterprise agency available to cities and counties 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. Regardless of whether or not Program Agreement 1 is approved and the CCA Program becomes operational, the parties intend for the Authority to continue to study, promote, develop, conduct, operate and manage other energy programs.

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 in Exhibit A, unless the context requires otherwise.

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:	Definitions
Exhibit B:	List of the Parties
Exhibit C:	Annual Energy Use
Exhibit D:	Voting Shares

1.3 **Revision of Exhibits**. The Parties agree that Exhibits B, C and D 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 MARIN ENERGY AUTHORITY

2.1 **Effective Date and Term**. This Agreement shall become effective and Marin Energy Authority shall exist as a separate public agency on the date this Agreement is executed by at least two Initial Participants after the adoption of the ordinances required by Public Utilities Code Section 366.2(c)(10). 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 7.4, subject to the rights of the Parties to withdraw from the Authority.

2.2 **Initial Participants**. During the first 180 days after the Effective Date, 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)(10) 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 and 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 Marin 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 board of each Party.

2.4 **Purpose**. The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party 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. Without limiting the generality of the foregoing, the Parties intend for this Agreement to be used as a contractual mechanism by which the Parties are authorized to participate as a group in the CCA Program, as further described in Section 5.1. The Parties intend that subsequent agreements shall define the terms and conditions associated with the actual implementation of the CCA Program and any other energy programs approved by the Authority.

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 make and enter into contracts;
2.5.2 employ agents and employees, including but not limited to an Executive Director;
2.5.3 acquire, contract, manage, maintain, and operate any buildings, works or improvements;
2.5.4 acquire 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 lease any property;
2.5.6 sue and be sued in its own name;
2.5.7 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 issue revenue bonds and other forms of indebtedness;
2.5.9 apply for, accept, and receive all licenses, permits, grants, loans or other aids from any federal, state or local public agency;

2.5.10 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;

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

2.5.12 make and enter into service agreements relating to the provision of services 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.

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 County of Marin.

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.

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 such 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 the Board satisfying the requirements described in Section 4.9.1, 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)(10) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership payment, if any, and (e) satisfaction of any conditions established by the Board. Notwithstanding the foregoing, in the event the Authority decides to not implement a CCA Program, the requirement that an additional party adopt the ordinance required by Public Utilities Code Section 366.2(c)(10) shall not apply. Under such circumstance, the Board resolution authorizing membership of an additional incorporated municipality or county shall be adopted in accordance with the voting requirements of Section 4.10.

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 and Removal of Directors**. The Directors shall be appointed and may be removed 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 Director or the alternate Director shall be a member of the governing body of the Party. As an alternative to appointing its own Director and alternate Director, the governing body of any Party may elect to designate another Party within the same county (the "designated Party") to represent it on the Board with the Director and alternate Director from the designated Party (the "consolidated Parties"). Notwithstanding any provision in this Agreement to the contrary, in the case of such an election by one or more Parties in the same county, the designated Party shall have the combined votes and voting shares of the consolidated Parties and shall vote on behalf of the consolidated Parties. The governing body of a Party may revoke its designation of another Party to vote on its behalf at any time. Neither an election by a Party to designate another Party to vote on its behalf or a revocation of this election shall be effective unless provided in a written notice to the Authority.

4.2.2 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.11, shall specify the reasons for and process associated with the removal of an individual Director for cause. Notwithstanding the foregoing, no Party shall be deprived of its right to seat a Director on the Board and any such Party for which its

Director and/or alternate Director has been removed may appoint a replacement.

4.3 **Terms of Office**. Each 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 any time. If at any time a vacancy occurs on the Board, a replacement shall be appointed to fill the position of the previous Director in accordance with the provisions of Section 4.2 within 90 days of the date that such position becomes vacant.

4.4 **Quorum**. A majority of the Directors shall constitute a quorum, except that less than a quorum may adjourn 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.

4.6 **Executive Committee**. The Board may 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 the Operating Rules and Regulations. The Board may not delegate to the Executive Committee or any other committee its authority under Section 2.5.11 to adopt and amend the Operating Rules and Regulations.

4.7 **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.

4.8 **Director Compensation**. Compensation for work performed by Directors on behalf of the Authority shall be borne by the Party that appointed the Director. The Board, however, may adopt by resolution a policy relating to the reimbursement of expenses incurred by Directors.

4.9 **Board Voting Related to the CCA Program**.

4.9.1. To be effective, on all matters specifically related to the CCA Program, a vote of the Board shall consist of the following: (1) a majority of all Directors shall vote in the affirmative or such higher voting percentage expressly set forth in Sections 7.2 and 8.4 (the "percentage vote") and (2) the corresponding voting shares (as described in Section 4.9.2 and Exhibit D) of all such Directors voting in the affirmative shall exceed 50%, or such other higher voting shares percentage expressly set forth in Sections 7.2 and 8.4 (the "percentage voting shares"), provided that, in instances in which such other higher voting share percentage would result in any one

Director having 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.

4.9.2. Unless otherwise stated herein, voting shares of the Directors shall be determined by combining the following: (1) an equal voting share for each Director determined in accordance with the formula detailed in Section 4.9.2.1, below; and (2) an additional voting share determined in accordance with the formula detailed in Section 4.9.2.2, below.

4.9.2.1 Pro Rata Voting Share. Each Director shall have an equal voting share as determined by the following formula: (1/total number of Directors) multiplied by 50, and

4.9.2.2 Annual Energy Use Voting Share. Each Director shall have an additional voting share as determined by the following formula: (Annual Energy Use/Total Annual Energy) multiplied by 50, where (a) "Annual Energy Use" means, (i) with respect to the first 5 years following the Effective Date, the annual electricity usage, expressed in kilowatt hours ("kWhs"), within the Party's respective jurisdiction and (ii) with respect to the period after the fifth anniversary of the Effective Date, the annual electricity usage, expressed in kWhs, of accounts within a Party's respective jurisdiction, and any additional jurisdictions which they represent, 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 C, and shall be adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 of each year

4.9.2.3 The voting shares are set forth in Exhibit D. Exhibit D may be updated to reflect revised annual energy use amounts and any changes in the parties to the Agreement without amending the Agreement provided that the Board is provided a copy of the updated Exhibit D.

4.10 Board Voting on General Administrative Matters and Programs Not Involving CCA. Except as otherwise provided by this Agreement or the Operating Rules and Regulations, each member shall have one vote on general administrative matters, including but not limited to the adoption and amendment of the Operating Rules and Regulations, and energy programs not involving CCA. Action on these items shall be determined by a majority vote of the quorum present and voting on the item or such higher voting percentage expressly set forth in Sections 7.2 and 8.4.

4.11 **Board Voting on CCA Programs Not Involving CCA That Require Financial Contributions.** The approval of any program or other activity not involving CCA that requires financial contributions by individual Parties shall be approved only by a majority vote of the full membership of the Board subject to the right of any Party who votes against the program or activity to opt-out of such program or activity pursuant to this section. The Board shall provide at least 45 days prior written notice to each Party before it considers the program or activity for adoption at a Board meeting. Such notice shall be provided to the governing body and the chief administrative officer, city manager or town manager of each Party. The Board also shall provide written notice of such program or activity adoption to the above-described officials of each Party within 5 days after the Board adopts the program or activity. Any Party voting against the approval of a program or other activity of the Authority requiring financial contributions by individual Parties may elect to opt-out of participation in such program or activity by providing written notice of this election to the Board within 30 days after the program or activity is approved by the Board. Upon timely exercising its opt-out election, a Party shall not have any financial obligation or any liability whatsoever for the conduct or operation of such program or activity.

4.12 **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 meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956. Directors may participate in meetings telephonically, with full voting rights, only to the extent permitted by law. All meetings of the Board shall be conducted in accordance with the provisions of the Ralph M. Brown Act (California Government Code Section 54950 et seq.).

4.13 **Selection of Board Officers.**

4.13.1 **Chair and Vice Chair**. The Directors shall select, 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 term of office of the Chair and Vice Chair shall continue for one year, but there shall be no limit on the number of terms held by either the Chair or Vice Chair. The office of either the Chair or Vice Chair shall be declared vacant and a new selection shall be made if: (a) the person serving dies, resigns, or the Party that the person represents removes the person as its representative on the Board or (b) the Party that he or she represents withdraws form the Authority pursuant to the provisions of this Agreement.

4.13.2 **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.

4.13.3 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. If the Board so designates, and in accordance with the provisions of applicable law, a qualified person may hold both the office of Treasurer and the office of Auditor of the Authority. Unless otherwise exempted from such requirement, the Authority shall cause an independent audit to be made 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. The duties and obligations of the Treasurer are further specified in Article 6.

4.14 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 a written agreement between the Authority and the appointed administrative services provider or providers that will be known as an Administrative Services Agreement. 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.

ARTICLE 5
IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 Preliminary Implementation of the CCA Program.

5.1.1 Enabling Ordinance. Except as otherwise provided by Section 3.1, prior to the execution of this Agreement, each Party shall adopt an ordinance in accordance with Public Utilities Code Section 366.2(c)(10) 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 4.9.

5.1.3 Effect of Vote On Required Implementation Action. In the event that two or more Parties vote to approve Program Agreement 1 or any earlier action required for the implementation of the CCA Program ("Required Implementation Action"), but such vote is insufficient to approve the Required Implementation Action under Section 4.9, the following will occur:

5.1.3.1 The Parties voting against the Required Implementation Action shall no longer be a Party to this Agreement and this Agreement shall be terminated, without further notice, with respect to each of the Parties voting against the Required Implementation Action at the time this vote is final. The Board may take a provisional vote on a Required Implementation Action in order to initially determine the position of the Parties on the Required Implementation Action. A vote, specifically stated in the record of the Board meeting to be a provisional vote, shall not be considered a final vote with the consequences stated above. A Party who is terminated from this Agreement pursuant to this section shall be considered the same as a Party that voluntarily withdrew from the Agreement under Section 7.1.1.1.

5.1.3.2 After the termination of any Parties pursuant to Section 5.1.3.1, the remaining Parties to this Agreement shall be only the Parties who voted in favor of the Required Implementation Action.

5.1.4 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 **Authority Documents**. The Parties acknowledge and agree that the affairs of the Authority will be implemented through various documents duly adopted by the Board through Board resolution, 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.

ARTICLE 6
FINANCIAL PROVISIONS

6.1 **Fiscal Year**. The Authority's fiscal year shall be 12 months commencing April 1 and ending March 31. 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. The Board shall contract with a certified public accountant or public accountant to make an annual audit of the accounts and records of the Authority, which shall be conducted in accordance with the requirements of Section 6505 of the Act.

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 County Funding of Initial Costs. The County of Marin shall fund the Initial Costs of the Authority in implementing the CCA Program in an amount not to exceed $500,000 unless a larger amount of funding is approved by the Board of Supervisors of the County**.** This funding shall be paid by the County at the times and in the amounts required by the Authority. In the event that the CCA Program becomes operational, these Initial Costs paid by the County of Marin shall be included in the customer charges for electric services as provided by Section 6.3.4 to the extent permitted by law, and the County of Marin 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 of Marin shall not be entitled to any reimbursement of the Initial Costs it has paid from the Authority or any Party.

6.3.3 CCA Program Costs. The Parties desire that, to the extent reasonably practicable, all costs incurred by the Authority that are directly or indirectly attributable to the provision of electric services under the CCA Program, including the establishment and maintenance of various reserve and performance funds, shall be recovered through charges to CCA customers receiving such electric services.

6.3.4 General Costs. Costs that are not directly or indirectly attributable to the provision of electric services under the CCA Program, as determined by the Board, shall be defined as general costs. General costs shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

6.3.5 Other Energy Program Costs. Costs that are directly or indirectly attributable to energy programs approved by the Authority other than the CCA Program shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

ARTICLE 7
WITHDRAWAL AND TERMINATION

7.1 <u>Withdrawal</u>.

7.1.1 General.

7.1.1.1 Prior to the Authority's execution of Program Agreement 1, any Party may withdraw its membership in the Authority by giving no less than 30 days advance written notice of its election to do so, which notice shall be given to the Authority and each Party. To permit consideration by the governing body of each Party, the Authority shall provide a copy of the proposed Program Agreement 1 to each Party at least 90 days prior to the consideration of such agreement by the Board.

7.1.1.2 Subsequent to the Authority's execution of Program Agreement 1, 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 6 months advance written notice of its election to do so, which notice shall be given to the Authority and each Party, and upon such other conditions as may be prescribed in Program Agreement 1.

7.1.2 Amendment. Notwithstanding Section 7.1.1, a Party may withdraw its membership in the Authority following an amendment to this Agreement in the manner provided by Section 8.4.

7.1.3 Continuing Liability; Further Assurances. A Party that withdraws its membership in the Authority may be subject to certain continuing liabilities, as described in Section 7.3. 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. The Operating Rules and Regulations shall prescribe the rights if any of a withdrawn Party to continue to participate in those Board discussions and decisions affecting customers of the CCA Program that reside or do business within the jurisdiction of the Party.

7.2 **Involuntary Termination of a Party**. This Agreement may be terminated with respect to a Party for material non-compliance with provisions of this Agreement or the Authority Documents upon an affirmative vote of the Board in which the minimum percentage vote and percentage voting shares, as described in Section 4.9.1, shall be no less than 67%, excluding the vote and voting shares of the Party subject to possible termination. Prior to any vote to terminate this Agreement with respect to a Party, written notice of the proposed termination and the reason(s) for such termination shall be delivered to the Party whose termination is proposed at least 30 days prior to the regular Board meeting at which such matter shall first be discussed as an agenda item. The written notice of proposed termination shall specify the particular provisions of this Agreement or the Authority Documents that the Party has allegedly violated. The Party subject to possible termination

shall have the opportunity at the next regular Board meeting to respond to any reasons and allegations that may be cited as a basis for termination prior to a vote regarding termination. A Party that has had its membership in the Authority terminated may be subject to certain continuing liabilities, as described in Section 7.3. In the event that the Authority decides to not implement the CCA Program, the minimum percentage vote of 67% shall be conducted in accordance with Section 4.10 rather than Section 4.9.1.

7.3 **Continuing Liability; Refund**. Upon a withdrawal or involuntary termination of a Party, the Party shall remain responsible for any claims, demands, damages, or liabilities arising from the Party's membership in the Authority through the date of its withdrawal or involuntary termination, it being agreed that the Party shall not be responsible for any claims, demands, damages, or liabilities arising after the date of the Party's withdrawal or involuntary termination. In addition, such Party also shall be responsible for any costs or obligations associated with the Party's participation in any program in accordance with the provisions of any agreements relating to such program provided such costs or obligations were incurred prior to the withdrawal of the Party. 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 liability for the costs described above. Any amount of the Party's funds held on deposit with the Authority above that which is required to pay any liabilities or obligations shall be returned to the Party.

7.4 **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.

7.5 **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 program 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. Should

such efforts to settle a dispute, after reasonable efforts, fail, the dispute shall be settled by binding arbitration in accordance with policies and procedures established by the Board.

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 is necessary to protect the interests of the Authority, the Parties and the public. 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 by an affirmative vote of the Board in which the minimum percentage vote and percentage voting shares, as described in Section 4.9.1, shall be no less than 67%. The Authority shall provide written notice to all Parties of amendments to this Agreement, including the effective date of such amendments. A Party shall be deemed to have withdrawn its membership in the Authority effective immediately upon the vote of the Board approving 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. As described in Section 7.3, a Party that withdraws its membership in the Authority in accordance with the above-described procedure may be subject to continuing liabilities incurred prior to the Party's withdrawal. In the event that the Authority decides to not implement the CCA Program, the minimum percentage vote of 67% shall be conducted in accordance with Section 4.10 rather than Section 4.9.1.

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 48 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. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties.

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: Leon Garcia

Name: Leon Garcia

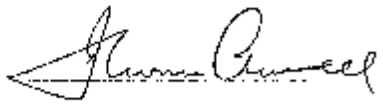
Title: Mayor

Date: 4.7.16

Party: City of American Canyon

ARTICLE 9
SIGNATURE

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

By: 

Name: Thomas Cromwell

Title: Mayor

Date: December 8, 2008

Party: City of Belvedere

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Elizabeth Patterson

Title: Mayor

Date: 12.29.14

Party: City of Benicia

APPROVED AS TO FORM
CITY ATTORNEY

ARTICLE 9

SIGNATURE

IN WITNESS WIIEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Dylan Feik

Title: City Manager

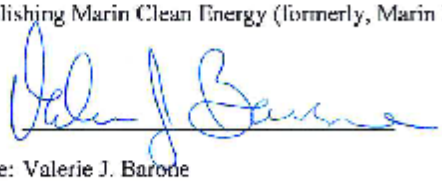
Date: April 7, 2016

Party: City of Calistoga

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: 

Name: Valerie J. Barone

Title: City Manager

Date: July 24, 2017

Party: City of Concord

ARTICLE 9
SIGNATURE

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

By: _____

Name: Alexandra Cock

Title: Mayor

Date: December 6, 2011

Party: Town of Corte Madera

ATTEST

_____
Christine Green, Town Clerk

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: 

Name: Joseph A. Calabrigo

Title: Town Manager

Date: July 17, 2017

Party: Town of Danville

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Scott Eaton

Title: City Manager

Date: 1/8/14

Party: City of El Cerrito

ARTICLE 9
SIGNATURE

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

By: David Weinsoff

Name: David Weinsoff

Title: Mayor

Date: 2.12.09

Party: Town of Fairfax

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Sean P. Quinn

Title: Interim City Manager

Date: 12/17/19

Party: City of Fairfield

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: DocuSigned by: Dante Hall 664EC62BC8D8428...

Name: Dante Hall

Title: City Manager

Date: 10/20/2023

Party: City of Hercules

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Mark Mitchell

Title: Mayor

Date: 3-14-16

Party: City of Lafayette

Attest:

_____

Joanne Robbins, City Clerk

ARTICLE 9
SIGNATURE

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

By: _____

Name: Larry Chu

Title: Mayor, Larkspur

Date: November 16, 2011

Party: CITY OF LARKSPUR

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Brad Kilger

Title: City Manager

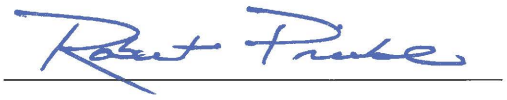
Date: 7/26/17

Party: City of Martinez

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: 

Name: Robert Priebe

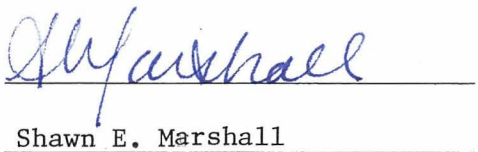
Title: Town Manager

Date: July 24, 2017

Party: Town of Moraga

ARTICLE 9
SIGNATURE

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

By: 

Name: Shawn E. Marshall

Title: Mayor

Date: December 2, 2008

Party: City of Mill Valley

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Mike Parness

Title: City Manager

Date: 4-11-16

Party: City of Napa

ARTICLE 9
SIGNATURE

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

By: Madeline R. Kellner

Name: Madeline R. Kellner

Title: Mayor

Date: October 7, 2011

Party: City of Novato

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Bryan H. Montgomery

Title: City Manager

Date: 8/1/17

Party: City of Oakley

ARTICLE 9
SIGNATURE

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

By: Michelle Fitzer

Name: Michelle Fitzer

Title: City Manager

Date: 7/5/17

Party: City of Pinole

Approved as to form:

By: Eric Casher

Name: Eric Casher

Title: City Attorney

Date: 7/5/17

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Joe Sbranti

Title: City Manager

Date: 7/24/2017

Party: City of Pittsburg

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: June Catalano

Title: City Manager

Date: June 19, 2019

Party: City of Pleasant Hill

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority

By: Gayle McLaughlin

Name: Gayle McLaughlin

Title: Mayor

Date: 7/5/12

Party: City of Richmond

ARTICLE 9
SIGNATURE

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

By: _____

Name: Carla Small

Title: Mayor

Date: 11/16/11

Party: Town of Ross

ARTICLE 9
SIGNATURE

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

By: _____

Name: Peter Breen

Title: Mayor

Date: January 9, 2009

Party: Town of San Anselmo

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Paul V. Morris

Title: Mayor, City of San Pablo

Date: SEPT. 16, 2014

Party: City of San Pablo

ARTICLE 9
SIGNATURE

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

By: Cyr N. Miller

Name: Cyr N. Miller

Title: Vice Mayor

Date: December 1, 2008

Party: City of San Rafael

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: JOE GORTON

Title: CITY MANAGER

Date: 7/31/17

Party: City of San Ramon

ARTICLE 9
SIGNATURE

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

By: Amy Belser

Name: Amy Belser

Title: Mayor

Date: November 18, 2008

Party: City of Sausalito

Attest:

Deputy City Clerk

Item: 5A
Meeting Date: 11-18-08
Page #: 24

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: Alan Galbraith

Name: Alan Galbraith

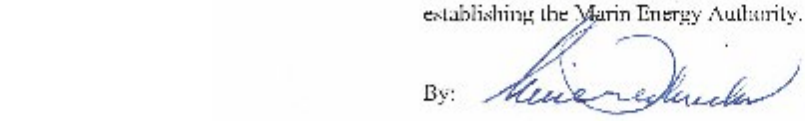
Title: Mayor

Date: 4/14/16

Party: City of St. Helena

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint
establishing the Marin Energy Authority.

By: 

Name: ALICE FREDERICKS

Title: MAYOR

Date: 2/10/09

Party: TOWN OF TIBURON

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: 
Greg Nyhoff

Name:

Title: City Manager

Date: June 12, 2019

Party: City of Vallejo

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: Loella Haskew

Name: LOELLA HASKEW

Title: MAYOR

Date: 4/13/16

Party: City of Walnut Creek

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Steven R. Rogers

Title: Town Manager

Date: 4/12/16

Party: Town of Yountville

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Federal D. Glover

Title: Chair, Board of Supervisors

Date: August 1, 2017

Party: Contra Costa County

ARTICLE 9
SIGNATURE

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

By: _____

Name: CHARLES F. McGLASHAN

Title: PRESIDENT, BD OF SUPERVISORS

Date: November 18 2008

Party: COUNTY OF MARIN

ARTICLE 9

Marin Clean Energy JPA Agreement

SIGNATURE

Amendment No. 8

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Mark Luce,

Title: Chairman, Napa County Board of Supervisors

Date: 7/22/14

Party: Napa County

Approved as to form:

_____ Date 7/21/14

Minh Tran,

County Counsel

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: _____

Name: Birgitta E. Corsello

Title: County Administrator

Date: 9/26/18

Party: County of Solano

APPROVED AS TO FORM:

_____
Solano County Counsel

Exhibit A

To the
Joint Powers Agreement
Marin Energy Authority

-Definitions-

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

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

"Administrative Services Agreement" means an agreement or agreements entered into after the Effective Date by the Authority with an entity that will perform tasks necessary for planning, implementing, operating and administering the CCA Program or any other energy programs adopted by the Authority.

"Agreement" means this Joint Powers Agreement.

"Annual Energy Use" has the meaning given in Section 4.9.2.2.

"Authority" means the Marin Energy Authority.

"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.

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

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

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

"Director" means a member of the Board of Directors representing a Party.

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

"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.

"Initial Costs" means all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as the hiring of an Executive Director and any administrative staff, any required accounting, administrative, technical and legal services in support of the Authority's initial activities or in support of the negotiation, preparation and approval of one or more Administrative Services Provider Agreements and Program Agreement 1. Administrative and operational costs incurred after the approval of Program Agreement 1 shall not be considered Initial Costs.

"Initial Participants" means, for the purpose of this Agreement, the signatories to this JPA as of May 5, 2010 including City of Belvedere, Town of Fairfax, City of Mill Valley, Town of San Anselmo, City of San Rafael, City of Sausalito, Town of Tiburon and County of Marin.

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

"Parties" means, collectively, the signatories to this Agreement that have satisfied the conditions in Sections 2.2 or 3.2 such that it is considered a member of the Authority.

"Party" means, singularly, a signatory to this Agreement that has satisfied the conditions in Sections 2.2 or 3.2 such that it is considered a member of the Authority.

"Program Agreement 1" means the agreement that the Authority will enter into with an energy service provider that will provide the electricity to be distributed to customers participating in the CCA Program.

"Total Annual Energy" has the meaning given in Section 4.9.2.2.

Exhibit B

To the
Joint Powers Agreement
Marin Energy Authority

-List of the Parties-

City of American Canyon
City of Belvedere
City of Benicia
City of Calistoga
City of Concord
Town of Corte Madera
Town of Danville
City of El Cerrito
Town of Fairfax
City of Fairfield
City of Hercules
City of Lafayette
City of Larkspur
City of Martinez
Town of Moraga
City of Mill Valley
City of Napa
City of Novato
City of Oakley
City of Pinole
City of Pittsburg
City of Pleasant Hill City of Richmond Town of Ross
Town of San Anselmo
City of San Pablo
City of San Rafael
City of San Ramon
City of Sausalito
St. Helena
Town of Tiburon
City of Vallejo
City of Walnut Creek
Town of Yountville
County of Contra Costa
County of Marin County of Napa
County of Solano

Marin Clean Energy

- Annual Energy Use -

This Exhibit C is effective as of November 16, 2023.

MCE Member Community	kWh (2022)
City of American Canyon	81,427,344
City of Belvedere	8,237,519
City of Benicia	94,928,828
City of Calistoga	28,672,196
City of Concord	464,522,261
Town of Corte Madera	40,679,971
County of Contra Costa	641,627,822
Town of Danville	154,016,934
City of El Cerrito	55,954,420
Town of Fairfax	17,441,179
City of Fairfield*	452,596,498
City of Hercules**	75,602,000
City of Lafayette	91,628,665
City of Larkspur	41,529,142
City of Martinez	144,050,725
City of Mill Valley	44,544,689
County of Marin	225,874,556
Town of Moraga	42,086,139
City of Napa	273,494,891
County of Napa	296,199,222
City of Novato	188,226,487
City of Oakley	111,135,099
City of Pinole	57,339,339
City of Pittsburg	232,985,737
City of Pleasant Hill	130,900,910
City of Richmond	387,473,558
Town of Ross	9,860,762
Town of San Anselmo	31,648,284
City of San Ramon	270,273,787
City of Saint Helena	44,870,258
City of San Pablo	63,297,704
City of San Rafael	206,521,192
City of Sausalito	30,635,006
County of Solano	177,643,279
Town of Tiburon	27,721,503
City of Vallejo	335,923,675
City of Walnut Creek	323,700,192
Town of Yountville	30,326,651
MCE Total Energy Use	5,935,598,420

*2020 usage data as provided by PG&E.
**2021/2022 usage data as provided by PG&E.
All other usage data reflects MCE customer billing records for 2022.

Marin Clean Energy

- Voting Shares -

This Exhibit D is effective as of November 16, 2023.

MCE Member Community	kWh (2022)	Section 4.9.2.1	Section 4.9.2.2	Voting Share
City of American Canyon	81,427,344	1.32%	0.69%	***2.00%***
City of Belvedere	8,237,519	1.32%	0.07%	***1.39%***
City of Benicia	94,928,828	1.32%	0.80%	***2.12%***
City of Calistoga	28,672,196	1.32%	0.24%	***1.56%***
City of Concord	464,522,261	1.32%	3.91%	***5.23%***
Town of Corte Madera	40,679,971	1.32%	0.34%	***1.66%***
County of Contra Costa	641,627,822	1.32%	5.40%	***6.72%***
Town of Danville	154,016,934	1.32%	1.30%	***2.61%***
City of El Cerrito	55,954,420	1.32%	0.47%	***1.79%***
Town of Fairfax	17,441,179	1.32%	0.15%	***1.46%***
City of Fairfield*	452,596,498	1.32%	3.81%	***5.13%***
City of Hercules**	75,602,000	1.32%	0.64%	***1.95%***
City of Lafayette	91,628,665	1.32%	0.77%	***2.09%***
City of Larkspur	41,529,142	1.32%	0.35%	***1.67%***
City of Martinez	144,050,725	1.32%	1.21%	***2.53%***
City of Mill Valley	44,544,689	1.32%	0.38%	***1.69%***
County of Marin	225,874,556	1.32%	1.90%	***3.22%***
Town of Moraga	42,086,139	1.32%	0.35%	***1.67%***
City of Napa	273,494,891	1.32%	2.30%	***3.62%***
County of Napa	296,199,222	1.32%	2.50%	***3.81%***
City of Novato	188,226,487	1.32%	1.59%	***2.90%***
City of Oakley	111,135,099	1.32%	0.94%	***2.25%***
City of Pinole	57,339,339	1.32%	0.48%	***1.80%***
City of Pittsburg	232,985,737	1.32%	1.96%	***3.28%***
City of Pleasant Hill	130,900,910	1.32%	1.10%	***2.42%***
City of Richmond	387,473,558	1.32%	3.26%	***4.58%***
Town of Ross	9,860,762	1.32%	0.08%	***1.40%***
Town of San Anselmo	31,648,284	1.32%	0.27%	***1.58%***
City of San Ramon	270,273,787	1.32%	2.28%	***3.59%***
City of Saint Helena	44,870,258	1.32%	0.38%	***1.69%***
City of San Pablo	63,297,704	1.32%	0.53%	***1.85%***
City of San Rafael	206,521,192	1.32%	1.74%	***3.06%***
City of Sausalito	30,635,006	1.32%	0.26%	***1.57%***
County of Solano	177,643,279	1.32%	1.50%	***2.81%***
Town of Tiburon	27,721,503	1.32%	0.23%	***1.55%***
City of Vallejo	335,923,675	1.32%	2.83%	***4.15%***
City of Walnut Creek	323,700,192	1.32%	2.73%	***4.04%***
Town of Yountville	30,326,651	1.32%	0.26%	***1.57%***
MCE Total Energy Use	5,935,598,420	50.00%	50.00%	***100.00%***

*2020 usage data as provided by PG&E.
**2021/2022 usage data as provided by PG&E.
All other usage data reflects MCE customer billing records for 2022.

Exhibit C
Marin Clean Energy
-Annual Energy Use-

This Exhibit C is effective as of May 16, 2024.

MCE Member Community	kWh (2023)
City of American Canyon	79,207,390
City of Belvedere	8,518,874
City of Benicia	92,488,603
City of Calistoga	29,971,557
City of Concord	441,711,055
Town of Corte Madera	40,409,990
County of Contra Costa	629,262,083
Town of Danville	144,559,397
City of El Cerrito	56,549,292
Town of Fairfax	18,480,057
City of Fairfield	418,972,628
City of Hercules*	75,602,000
City of Lafayette	89,704,826
City of Larkspur	40,926,401
City of Martinez	135,776,703
City of Mill Valley	46,345,910
County of Marin	228,173,442
Town of Moraga	41,597,219
City of Napa	262,216,341
County of Napa	292,640,197

City of Novato	**184,699,898**
City of Oakley	**104,654,511**
City of Pinole	**55,630,390**
City of Pittsburg	**216,424,897**
City of Pleasant Hill	**119,997,753**
City of Richmond	**389,966,133**
Town of Ross	**9,915,147**
Town of San Anselmo	**31,632,018**
City of San Ramon	**262,986,004**
City of Saint Helena	**44,372,121**
City of San Pablo	**61,307,992**
City of San Rafael	**205,395,814**
City of Sausalito	**31,301,320**
County of Solano	**158,463,487**
Town of Tiburon	**29,028,081**
City of Vallejo	**320,808,503**
City of Walnut Creek	**303,238,670**
Town of Yountville	**26,477,825**
MCE Total Annual Energy Use	**5,729,414,528**

*Because the City of Hercules was just approved as a member community in November 2023 and will not receive service until April 2025, MCE must rely on prior historical usage data provided by Pacific Gas & Electric Company (the most current being from 2021/2022).
All other usage data reflects MCE customer billing records for 2023.

Exhibit D
Marin Clean Energy
-Voting Shares-

This Exhibit D is effective as of May 16, 2024.

MCE Member Community	kWh (2022)	Section 4.9.2.1	Section 4.9.2.2	Voting Share
City of American Canyon	79,207,390	1.32%	0.69%	**2.01%**
City of Belvedere	8,518,874	1.32%	0.07%	**1.39%**
City of Benicia	92,488,603	1.32%	0.81%	**2.12%**
City of Calistoga	29,971,557	1.32%	0.26%	**1.58%**
City of Concord	441,711,055	1.32%	3.85%	**5.17%**
Town of Corte Madera	40,409,990	1.32%	0.35%	**1.67%**
County of Contra Costa	629,262,083	1.32%	5.49%	**6.81%**
Town of Danville	144,559,397	1.32%	1.26%	**2.58%**
City of El Cerrito	56,549,292	1.32%	0.49%	**1.81%**
Town of Fairfax	18,480,057	1.32%	0.16%	**1.48%**
City of Fairfield	418,972,628	1.32%	3.66%	**4.97%**
City of Hercules*	75,602,000	1.32%	0.66%	**1.98%**
City of Lafayette	89,704,826	1.32%	0.78%	**2.10%**
City of Larkspur	40,926,401	1.32%	0.36%	**1.67%**
City of Martinez	135,776,703	1.32%	1.18%	**2.50%**
City of Mill Valley	46,345,910	1.32%	0.40%	**1.72%**
County of Marin	228,173,442	1.32%	1.99%	**3.31%**
Town of Moraga	41,597,219	1.32%	0.36%	**1.68%**
City of Napa	262,216,341	1.32%	2.29%	**3.60%**
County of Napa	292,640,197	1.32%	2.55%	**3.87%**
City of Novato	184,699,898	1.32%	1.61%	**2.93%**
City of Oakley	104,654,511	1.32%	0.91%	**2.23%**

City of Pinole	55,630,390	1.32%	0.49%	**1.80%**
City of Pittsburg	216,424,897	1.32%	1.89%	**3.20%**
City of Pleasant Hill	119,997,753	1.32%	1.05%	**2.36%**
City of Richmond	389,966,133	1.32%	3.40%	**4.72%**
Town of Ross	9,915,147	1.32%	0.09%	**1.40%**
Town of San Anselmo	31,632,018	1.32%	0.28%	**1.59%**
City of San Ramon	262,986,004	1.32%	2.30%	**3.61%**
City of Saint Helena	44,372,121	1.32%	0.39%	**1.70%**
City of San Pablo	61,307,992	1.32%	0.54%	**1.85%**
City of San Rafael	205,395,814	1.32%	1.79%	**3.11%**
City of Sausalito	31,301,320	1.32%	0.27%	**1.59%**
County of Solano	158,463,487	1.32%	1.38%	**2.70%**
Town of Tiburon	29,028,081	1.32%	0.25%	**1.57%**
City of Vallejo	320,808,503	1.32%	2.80%	**4.12%**
City of Walnut Creek	303,238,670	1.32%	2.65%	**3.96%**
Town of Yountville	26,477,825	1.32%	0.23%	**1.55%**
MCE Total Energy Use	5,729,414,528	50.00%	50.00%	**100.00%**

* Because the City of Hercules was just approved as a member community in November 2023 and will not receive service until April 2025, MCE must rely on prior historical usage data provided by Pacific Gas & Electric Company (the most current being from 2021/2022).

All other usage data reflects MCE customer billing records for 2023.

MCE Board Offices and Committee Rosters

BOARD OFFICES

Chair:	Shanelle Scales-Preston, City of Pittsburg
Vice Chair:	Gabe Quinto, City of El Cerrito
Treasurer:	Garth Salisbury, MCE Chief Financial Officer
Deputy Treasurer:	Vicken Kasarjian, MCE Chief Operating Officer
Secretary:	Dawn Weisz, MCE Chief Executive Officer

BOARD OFFICES SECTION PROCESS

The Chair and Vice Chair offices are held for 1 year and there are no limits on the number of terms held by either Chair or Vice Chair.[1] The selection of these offices shall take place on or near December of each year.[2] The office of Treasurer is appointed by the Board via an approved resolution and may be a non-board member. The Treasurer appointment, along with the delegated authority, is held for 1 year and there are no limits on the number of terms held.[3] Deputy Treasurers are appointed directly by the Treasurer each year. Once appointed by the Board, the Secretary shall continue to hold the office each year until the Secretary chooses to resign from the role or the Board decides to remove the individual from the Secretary position.[4] The Secretary does not need to be a member of the Board. All officer appointments/selections by the Board require a majority vote of the full membership of the Board.[5]

EXECUTIVE COMMITTEE *(Membership Approved 2.15.24)*

1. Max Perrey, Chair	City of Mill Valley
2. Eli Beckman	Town of Corte Madera
3. Cindy Darling	City of Walnut Creek
4. Dave Fong	City of Danville
5. Maika Llorens Gulati	City of San Rafael
6. Eduardo Martinez	City of Richmond
7. Devin Murphy	City of Pinole
8. Gabe Quinto	City of El Cerrito
9. Shanelle Scales-Preston	City of Pittsburg
10. Holli Thier	Town of Tiburon
11. Sally Wilkinson	City of Belvedere
Laura Nakamura	City of Concord (Interested)

[1] Section 4.13.1 of MCE Joint Powers Agreement.
[2] Article V, Section 1 of MCE's Operating Rules and Regulations.
[3] Article V, Section 1 of MCE's Operating Rules and Regulations; California Government Code § 53607.
[4] Article IV, Section 1(c) of MCE's Operating Rules and Regulations.
[5] Article VI, Section 2 of MCE's Operating Rules and Regulations. At MCE's current membership of 37 communities with appointed Directors, the vote needed is 19.

TECHNICAL COMMITTEE *(Membership Approved 2.15.24)*

1. Devin Murphy, Chair	City of Pinole
2. Gina Dawson	City of Lafayette
3. Alexis Fineman	Town of San Anselmo
4. John Gioia	County of Contra Costa
5. Eduardo Martinez	City of Richmond
6. Charles Palmares	City of Vallejo
7. Scott Perkins	City of San Ramon
8. Katie Rice	County of Marin
9. Gabe Quinto	City of El Cerrito

AD HOC CONTRACTS COMMITTEE, 2024

1. Barbara Coler	Town of Fairfax
2. Cindy Darling	City of Walnut Creek
3. Aaron Meadows	City of Oakley
4. Gabe Paulson	City of Larkspur
5. Scott Perkins	City of San Ramon
6. Katie Rice	County of Marin
7. Sally Wilkinson	City of Belvedere

AD HOC AUDIT COMMITTEE, 2024

1. Dave Fong	Town of Danville
2. Laura Nakamura	City of Concord
3. Gabriel Quinto	City of El Cerrito
4. Sally Wilkinson	City of Belvedere

AD HOC CAPITAL PROJECTS COMMITTEE, 2024

The Ad Hoc Capital Projects Committee will consider strategies for risk mitigation which include possible ownership of fossil-free generating resources, grid enhancing technologies for transmission access, and consolidation of office spaces, with a potential shift from leasing to ownership.

MCE Executive Committee Overview

Scope

The scope of the MCE Executive Committee is to explore, discuss and provide direction or approval on general issues related to MCE including legislation, regulatory compliance, strategic planning, outreach and marketing, contracts with vendors, human resources, finance and budgeting, debt, rate setting, and agenda setting for the regular MCE Board meetings and annual Board retreat.

Authority

Executive Committee is authorized to make decisions regarding:

- Legislative positions outside of the Board-approved legislative plan
- Procurement pursuant to Resolution 2018-04 or its successor
- Compensation and evaluation of the CEO
- Ad hoc committees
- Honorary awards

The Executive Committee also serves to make recommendations to the Board regarding:

- The annual budget and budget adjustments
- Rate setting
- Entering into debt
- MCE Policies (such as Policy 013: Reserve Policy and Policy 014: Investment Policy)

Committee Member Selection Process

MCE strives to assemble an Executive Committee comprised of at least one county representative and one city/town representative from each county in the MCE service area. Available seats on the Executive Committee are therefore first offered to any interested and applicable Board member whose county is not yet represented by one county and one city/town member. Interested members can be added at a meeting of the Board of Directors when it is included in the agenda.

Current Meeting Schedule

First Wednesday of each month at 12:00 pm

MCE Technical Committee Overview

Scope

The scope of the MCE Technical Committee is to explore, discuss and provide direction or approval on issues related to electricity supply, distributed generation, greenhouse gas emissions, energy efficiency, procurement risk management and other topics of a technical nature.

Frequent topics include electricity generation technology and procurement, greenhouse gas accounting and reporting, energy efficiency programs and technology, energy storage technology, net energy metering tariff, local solar rebates, electric vehicle programs and technology, Feed-in Tariff activity and other local development, Light Green, Deep Green and Local Sol power content planning, long term integrated resource planning, regulatory compliance, MCE's Energy Risk Management Policy (ERMP), procurement risk oversight, and other activity related to the energy sector. The MCE Technical Committee reviews and discusses new technologies and potential application by MCE.

Authority

- Approval of and changes to MCE's Net Energy Metering Tariff
- Approval of and changes to MCE's Feed in Tariff
- Approval of annual greenhouse gas emissions level and related reporting
- Approval of MCE procurement pursuant to Resolution 2018-03 or its successor
- Approval of MCE procurement-related certifications and reporting, including the Power Content Label
- Approval of contracts with vendors for technical programs or services, energy efficiency program or services and procurement functions or services
- Approval of power purchase agreements
- Approval of adjustments to power supply product offerings
- Approval of the Integrated Resource Plan
- Receipt of reports from the Risk Oversight Committee (ROC) on at least a quarterly basis regarding the ROC's meetings, deliberations, and any other areas of concern
- Initiation of and oversight of a review of the implementation of the ERMP as necessary
- Approval of substantive changes to MCE's Energy Risk Management Policy (ERMP), including periodic review of the ERPM and periodic review of ERPM implementation

Committee Member Selection Process

MCE strives to assemble a Technical Committee comprised of at least one county representative and one city/town representative from each county in the MCE service area. Available seats on the Technical Committee are therefore first offered to any interested and applicable Board member whose county is not yet represented by one county and one city/town member. Interested members can be added at a meeting of the Board when it is included in the agenda.

Current Meeting Schedule

First Friday of each month at 10:00 am

May 16, 2024

TO: MCE Board of Directors

FROM: Sabrinna Soldavini, Manager of Policy
Justin Kudo, Senior Strategic Analysis and Rates Manager

RE: Proposed MCE Load Management Standards Plan (Agenda Item #07)

ATTACHMENT: MCE Load Management Standards Plan

Dear Board Members:

Summary:
Staff recommends the Board adopt MCE's Proposed Load Management Standards Plan ("Proposed Plan") and authorize Staff to submit the adopted Proposed Plan to the California Energy Commission within 30 days of Board adoption.

Background
The California Energy Commission ("CEC") approved amended Load Management Standards ("LMS") through a CEC Rulemaking process, effective April 2023. The revised LMS requests Load Serving Entities ("LSEs")[1] develop and publish hourly or sub-hourly rates ("dynamic rates") and/or programs for all customer classes that help to: (1) materially reduce peak electricity demand; (2) balance electricity supply and demand to support grid reliability; and (3) and provide clean and affordable electricity services to Californians.

The revised LMS requests that MCE submit at least one dynamic rate to the Board for approval by July 1, 2025, for all customer classes where such a rate would materially reduce peak load. The LMS request that these dynamic rates, as well as MCE's current time-dependent rates, be published in a centralized location called the Market Informed Demand Automation Server ("MIDAS") database. The MIDAS database is intended to help customers understand, manage, and/or automate their load by providing access to current electricity rates and other real-time grid signals.

[1] Including Community Choice Aggregators (CCAs), publicly owned utilities, and investor-owned utilities (IOUs).

The LMS also requests that MCE create and submit a plan to its Board by April 1, 2024, outlining how it intends to meet the goals of the LMS, and consider it at a duly noticed public meeting within 60 days. Upon approval by the Board, the LMS requests MCE submit the plan to the CEC for review. The attached Proposed Plan was provided to the Board on March 29, 2024, for consideration prior to this meeting.

Staff notes that the CEC does not have jurisdiction over CCA rate setting as that responsibility is governed by the MCE Board of Directors. However, MCE shares the goals and objectives of the LMS to better align electricity supply and demand and to encourage automated load shifting away from peak periods to reduce costs for all ratepayers. The Proposed Plan outlines the steps and activities that MCE plans to voluntarily undertake by July 1, 2025, which align with the goals of the LMS.

MCE does not currently have the necessary data to conclude that offering dynamic rates, as requested by the CEC, would be cost effective or materially reduce peak load beyond that of MCE's current rate and program offerings for any customer class. As a result, the attached Proposed Plan, finds that MCE may, but is not required to, create and submit such a rate for approval by the target date of July 1, 2025.[2]

This modification of the LMS' timeline to create dynamic rates is required to ensure MCE can gather and sufficiently evaluate the data necessary to determine the cost effectiveness, equity, and benefits to customers of any future dynamic rate offerings. MCE plans to collect such data through the creation of, or participation in, future pilots or through evaluation of relevant pilot data (e.g. non-MCE pilots that take place in MCE or Pacific Gas & Electric's service area).

MCE currently offers a robust portfolio of load flexibility programs aimed at encouraging customers to use energy in off-peak hours including: (1) MCE's Peak FLEXmarket – a market-driven demand flexibility program; (2) MCE Sync – a managed electric vehicle charging program; (3) MCE's Residential and Commercial Efficiency programs; (4) MCE's Solar Storage Credit program that incentivizes customers to automate their battery to discharge at peak-hours; and (4) MCE's Richmond Virtual Power Plant pilot, which is expected to launch in 2025.

At this time, MCE plans to continue to offer its portfolio of current and planned load flexibility programs and time dependent rates and will continue to explore how it may offer new cost-effective dynamic rates, pilots, and load-flexibility programs that materially reduce peak load, encourage load control through automation, and provide reliability and environmental benefits for MCE customers and the California electric grid.

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[2] As outlined in LMS § 1623.1(a)(2), MCE's Board may approve a plan, or material revisions to a previously approved plan, that delays implementation of or modifies the goals of LMS § 1623.1(b)-(c), if the Board determines that despite good faith efforts implementation: (1) would result in extreme hardship to MCE; (2) would result in reduced system reliability (e.g., equity or safety) or efficiency; (3) would not be technologically feasible or cost effective; or (4) must be modified to provide a more technologically feasible, equitable, safe, or cost-effective way to achieve the LMS or plan's goals.

Fiscal Impacts:

There are no immediate fiscal impacts associated with the adoption of MCE's Proposed Plan, and the Proposed Plan is intended to minimize risk and cost to MCE and its customers. If dynamic rates are created and submitted to the Board for approval, Staff will prepare the financial impacts of such rates for review.

Recommendation:

Adopt and authorize staff to submit MCE's Proposed Load Management Standards Plan to the CEC within 30 days of Board adoption.

MARIN CLEAN ENERGY

LOAD MANAGEMENT STANDARDS PLAN

March 29, 2024

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2 Introduction

2.1 About MCE

Marin Clean Energy ("MCE") is California's first Community Choice Aggregation ("CCA") Program, a not-for-profit Joint Powers Authority ("JPA") that began serving customers in 2010. MCE's mission is to confront the climate crisis by eliminating fossil fuel greenhouse gas ("GHG") emissions, producing renewable energy, and creating equitable community benefits. MCE's vision is to lead California to an equitable, clean, affordable, and reliable energy economy by serving as a model for community-based renewable energy, energy efficiency, and cutting-edge clean-tech products and programs.

As a load-serving entity ("LSE") MCE provides electricity generation service to approximately 580,000 customer accounts. These accounts represent more than one million residents and businesses across four Bay Area counties.[1] MCE procures for annual retail sales of approximately 5,729 GWh and a peak load of more than 1,240 MW.

MCE provides service to approximately 87 percent of eligible customers within its service area, which is depicted below in Figure 1. MCE is also the default generation provider for any new or relocated customers therein.

Figure 1: MCE Service Area Map

[1] MCE serves communities across Contra Costa, Marin, Napa, and Solano counties. Those communities currently receiving service include: Unincorporated Contra Costa, Marin, Napa, and Solano counties and the Cities and Towns of Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Pleasant Hill, Richmond, San Pablo, San Ramon, Walnut Creek, Belvedere, Corte Madera, Fairfax, Larkspur, Mill Valley, Novato, Ross, San Anselmo, San Rafael, Sausalito, Tiburon, American Canyon, Calistoga, Napa, St. Helena, Yountville, Benicia, Vallejo, and Fairfield. MCE expects service to expand to include the City of Hercules in April of 2025.

As a JPA and local government agency, MCE is governed by a 34-member Board of Directors ("Board" or "Governing Board") composed of elected representatives from MCE's member communities. MCE's Board sets policy for the agency and oversees operations, including rates and procurement planning. Through these representatives, MCE is controlled by and accountable to the communities MCE serves.

MCE was formed to empower its member communities to choose the generation resources that reflect their specific values and needs. As a mission-driven local government agency, MCE works toward the following:

- Reducing GHG emissions and accelerating the supply of clean energy being delivered to and used on the grid;
- Developing community programs and local energy projects to expand access to competitively priced renewable energy and energy efficiency programs for all customers;
- Creating economic and workforce benefits associated with renewable energy and energy conservation programs; and
- Leveraging energy and conservation spending to promote more equity throughout MCE's communities and California.

2.2 Load Management Standards

In Docket Number 21-OIR-03 the California Energy Commission ("CEC") adopted Revised Load Management Standards ("LMS" or "Standards"). The amendments to the LMS, which became effective on April 1, 2023, are intended to form the foundation for a statewide system of time and locational dependent signals that can be used by automation-enabled devices to encourage load flexibility on the electric grid. Simply, the Standards are intended to encourage automated load shifting of electricity to off-peak hours.

To accomplish the goals of the LMS, the regulations request California's large CCAs,[2] investor-owned utilities ("IOUs"), and large publicly owned utilities ("POUs") to offer customers access to rate-structures and/or programs that allow automated responses to prices or other grid signals to manage and optimize their energy use.

Specifically, the LMS request large CCAs to (1) develop and propose marginal cost-based rates that vary at least hourly[3] or, (2) if the Board finds that implementing marginal cost-based hourly rates would not materially reduce peak load, be technologically feasible, and/or be cost-effective, offer a load flexibility program that allows at least one option for automating response to the CEC's Market Informed Demand Automation Server ("MIDAS") signals for customer classes where MCE's Board determines such a program would materially reduce peak load and be cost-effective. For the purposes of this plan, MCE will refer to marginal cost-based rates that vary at least hourly as defined in the LMS as "hourly" or "dynamic" rates.

[2] The LMS define Large CCAs as any CCA that provides in excess 700 GWh of electricity to customers in any calendar year.

[3] Section 1623.1(b)(1) of the LMS define a marginal cost-based rate as the sum of the marginal energy cost, the marginal capacity cost (generation, transmission, and distribution), and any other appropriate time and location dependent marginal costs, including the locational marginal cost of associated greenhouse gas emissions, on a time interval of no more than one hour.

2.2.1 MCE LMS Plan and Board Authority

Section 1623.1(a) requests each large CCA submit a plan outlining how it plans to meet the objectives of the LMS to its Board by April 1, 2024.

As a large CCA that shares the goals and objectives of the LMS to better align demand of electricity with periods of high renewable energy supply and encouraging automated load shifting away from peak periods, MCE submits this plan to the Board for approval. [4] The purpose of this plan is to identify the steps and activities MCE plans to voluntarily undertake which align with the goals of the LMS.

MCE notes that nothing in this plan overrides or supersedes MCE's Board's sole authority as the governing and rate-making body of MCE.[5] Nothing in this plan implies any jurisdictional authority of the CEC over MCE's rates and rate programs. MCE is currently voluntarily taking reasonable steps that meet the standards within the LMS regulations.

Additionally, as outlined in the LMS, MCE's Board may approve a plan, or material revisions to a previously approved plan, that delays implementation of or modifies the goals of LMS Subsections 1623.1(b)-(c), if the Board determines that despite good faith efforts implementation:

- Would result in extreme hardship to MCE;
- Would result in reduced system reliability (e.g., equity or safety) or efficiency;
- Would not be technologically feasible or cost effective; or
- Must be modified to provide a more technologically feasible, equitable, safe, or cost-effective way to achieve the LMS or plan's goals.

Accordingly, MCE submits this plan to the Board for adoption and approval to implement as outlined herein. Table 1 below provides a list of each regulatory standard or goal as outlined in the LMS and MCE's plan to meet that standard or goal at the time of this writing. As described, MCE plans to continue to offer its portfolio of current and planned load flexibility programs and time dependent rates aimed at encouraging customers to use energy in off-peak hours, and will continue to explore how it may offer new cost-effective dynamic rates, pilots, and load flexibility programs that materially reduce peak load, encourage load control through automation, and provide reliability and environmental benefits for MCE customers and the California electric grid.

[4] Consistent with Section 1623.1(a) of the LMS, MCE submitted this plan to its Board on March 29, 2024, and will submit this plan to the CEC within 30 days of Board approval.

[5] Public Utilities Code Section 366.2(c)(3) provides that CCAs retain jurisdiction for setting rates for the electricity they purchase on behalf of their communities.

Table 1: MCE LMS Roadmap

Load Management Standards Section	Standard Description	Target Date	MCE Adopted Plan to Meet Standard
§1623.1(c)	Upload existing time-dependent rates to MIDAS database.	July 1, 2023	Status: Achieved MCE plans to maintain future rates in MIDAS to the extent it is cost effective and technologically feasible. MCE cannot confirm that uploading future dynamic rates or programs to MIDAS will be cost effective or technologically feasible.
§1623.1(a)(1)	Develop and submit a plan for adoption to MCE's Board addressing how MCE plans to meet objectives of the LMS. The plan is to be considered for adoption by MCE's Board within 60 days of submission at a duly noticed public meeting.	April 1, 2024	Status: Achieved
§1623.1(a)(3)(A)	Within 30 days of adoption of the plan, submit the plan to the CEC's Executive Director.	30 Days After Board Adoption	Status: MCE will submit this plan to the CEC within 30 days of Board adoption.
§1623(c)	Within one year of LMS effective date, provide customers access to their Rate Identification Numbers on billing statements and in online accounts using both text and quick response code format.	April 1, 2024	Status: In Progress, Expected to Achieve
§1623(c)	In conjunction with the other named LSEs, develop and submit to the CEC a plan for a single statewide standard tool for authorized rate data access by third parties and the terms and conditions for using the tool. Upon CEC approval, maintain and implement the tool.	October 1, 2024	Status: In Progress MCE is engaged in and monitoring the development process for the single statewide tool.

Load Management Standards Section	Standard Description	Target Date	MCE Adopted Plan to Meet Standard
§1623.1(b)(3)	Submit to the CEC a list of load flexibility programs deemed cost effective by MCE. The portfolio of programs should provide at least one option to automate response to MIDAS signals for each customer class where MCE's Board has determined such a program would materially reduce peak load.	October 1, 2024	Status: In Progress MCE cannot determine that such a program will materially reduce peak load for any customer class. MCE will submit a list of programs deemed cost effective to the CEC but does not expect to include an option to automate response to MIDAS signal at this time.
§1623.1(a)(3)(C)	Submit annual reports to the CEC demonstrating implementation of the plan, as approved by the Board.	Annually	Status: In Progress MCE will submit annual reports beginning one year after the adoption of this plan.
§1623.1(b)(2)	Submit at least one marginal cost-based rate to MCE's Board for approval for any customer class(es) where such a rate will materially reduce peak load. An Information copy of the tariff applications will be provided to the CEC.	July 1, 2025	Status: In Progress At this time MCE cannot determine that such a rate or will provide material, incremental reductions to peak load or be cost effective for any customer class. However, MCE is interested in collecting the data necessary to make such determinations and will continue to explore options to offer dynamic rate pilots in its service territory. MCE therefore recommends the Board modify this standard and determine that MCE may, but is not required to, propose such a rate or program by the target date. MCE will continue to evaluate and address in its next plan iteration and any annual reports.
§1623.1(b)(4)	Offer each customer voluntary participation in either a marginal cost-based rate, if approved by the Board, or a cost-effective load flexibility program.	July 1, 2027	Status: To be determined by future Board direction. MCE notes that this target date is after the next review of MCE's LMS is expected to be completed. As such, MCE will likely provide an update in its next LMS plan as appropriate.

Load Management Standards Section	Standard Description	Target Date	MCE Adopted Plan to Meet Standard
§1623.1(b)(5)	Conduct a public information program to inform and educate affected customers on why marginal cost-based rates or load flexibility programs and automation are needed, how they will be used, and how these rates and programs can save customers money.	No Target Date Specified	Status: To be determined by future Board direction and future adoption of dynamic rates or load-modifying programs.
§1623.1(a)(1)(C)	Review the plan at least once every three years after the plan is adopted and submit a plan update to the Board if there is a material change.	Once Every Three Years	Status: MCE will review its LMS plan at least once every three years following the date of adoption.

3 Access to Price Signals

3.1 Time-Dependent Rate Submission to MIDAS

Adopted LMS Amendments Section 1623.1(c) requests each Large CCA upload existing time dependent rates to the MIDAS database by July 1, 2023. On June 1, 2023, the CEC issued Order No. 23-0531-109 approving an extension for CCAs to upload time-dependent generation rates by August 1, 2023, and any remaining time-depending rates with rate modifiers by October 1, 2023. Large CCAs are also asked to upload any new time-dependent rates or changes to existing rates, prior to the effective date of that rate.

3.1.1 Existing Rates Upload

MCE successfully uploaded all of its 70 active Light Green service rates by the CEC's target date of August 1, 2023, and uploaded its Deep Green service rates by the target date of October 1, 2023, to include time-dependent rates with additional modifiers. A complete list of rates uploaded to MIDAS and their associated Rate Identification Numbers ("RIN") is included in Appendix A.

The period covered by the initial upload spanned between three and six months, due to data limitations of the MIDAS system. As such, MCE has made subsequent uploads to keep rates current in MIDAS:

1. In October 2023, MCE uploaded additional intervals to ensure all rates were up-to-date through December 31, 2023.

2. In November 2023, MCE uploaded additional intervals for all rates through May 1, 2024.[6]

3.1.2 Future Rates Upload

To the extent that uploading future rates is feasible and cost effective, MCE plans to maintain its generation rates in MIDAS so that customers and their devices may access them for device automation. However, MCE notes that if hourly rates are approved by MCE's Board, daily uploads of such rates to MIDAS will present significant challenges. Given the current structure of MIDAS and the lack of funding for LSEs to develop systems, processes, and improvements to MIDAS, MCE cannot at this time find that it is cost effective or feasible to maintain current and accurate rates for any future hourly rate offerings in MIDAS.

Nonetheless, MCE is engaged in and monitoring the Demand Flexibility Proceeding at the California Public Utilities Commission ("CPUC") and is committed to working with the CEC, CPUC, and other stakeholders to help customers automate behavioral changes in electric usage and looks forward to further discussion on how MIDAS may be updated and/or will interact with future rate platforms or repositories yet to be developed such as a CPUC approved Price Machine.

MCE recommends that any future rate repositories be equipped to provide composite rates if the goal is to provide customers with a composite or total real-time rate signal. As a CCA, MCE's Board has sole authority over its customers' generation rate component but has no authority to determine the distribution or transmission rate components of its customers' rates. Any distribution and transmission rate components charged to MCE customers are charged by Pacific Gas & Electric Company ("PG&E"). As such, MCE only plans to upload generation rate components to MIDAS and cannot take responsibility for, be required to calculate, or be required to upload marginal cost rates for rate components and myriad PG&E programs that it has no control over.

3.2 Plan to Provide Rate Identification Number(s) on Customer Billing Statements and Online Account Using Both Text and QR Code

Adopted LMS Amendments Section 1623(c)(4) requests each Large CCA to provide customers with access to their RIN on customer billing statements and online accounts using both text and quick response ("QR") or similar machine-readable digital code by April 1, 2024.

MCE customers receive their consolidated billing statements from PG&E. MCE provides itemized charges to PG&E through Electronic Data Interchange ("EDI") transactions. Therefore, MCE is reliant on PG&E to develop its EDI system to accept MCE RINs and display them on customer bills.

[6] As of this writing, six of MCE's Light Green rates are not current in the MIDAS system. These rates serve a small number of large Commercial & Industrial and EV customers with legacy 12p-6p peak periods. Upload attempts are rejected with the message, "An error has occurred." MCE reached first reached out to CEC staff on November 30, 2023, and has had numerous, ongoing communications with CEC staff on this matter. The issue appears to reside with MIDAS, and not with MCE. CEC Staff has indicated they are aware of the issue, that it is not isolated to MCE and the CEC is working to resolve the issue. MCE will continue to engage and collaborate with the CEC in good faith to fix this issue.

CCAs have been working with PG&E to utilize PG&E's billing transactions to include a CCA specific RIN on customers' bills. MCE will supply MCE's RIN mapping table to PG&E who will then include it within the code and display customers' RINs on the generation portion of their bills. This interpretation has also been corroborated by PG&E in recent CPUC Advice Letters seeking approval to modify customers' bill presentations to include RINs and QR codes.

On January 16, 2024, PG&E filed Advice Letter 7136-E at the CPUC outlining the process it is undertaking to provide RINs on customer bills. As outlined by PG&E in its second supplemental Advice Letter 7136-E-B filed on March 1, 2024, customers on time-dependent rates will have their bills updated to include a QR code and the customer's RIN in the top right-hand corner of their bill, which can then be scanned to program a customer's device(s). PG&E notes that RINs will be presented the same way on both bundled and unbundled (CCA and Direct Access) customers' bills.

3.3 Plans and Current Participation in the Development of Single Statewide RIN Access Tool

Adopted LMS Amendments Section 1623(c)(1)-(3) requests all LSEs named in the Standards to work together to develop a plan for a single statewide standard tool for authorized rate data access by third parties, along with a single set of terms and conditions for third parties using the tool by October 1, 2024. The tool is to provide the customers' RINs, provide eligible RINs, enable switching to an available rate by an authorized third party, incorporate applicable cybersecurity measures, minimize enrollment barriers, and be accessible in digital, machine-readable format.

MCE is monitoring and engaging in the process to develop a Single Statewide RIN Access Tool and will continue to collaborate with other parties on the tool's development ahead of the October 1, 2024, target date. At the time of this writing MCE is unable to specifically identify the full scope and budget of integration of work; commit resources; or review, identify, and plan internal infrastructure needs until the Single Statewide Standard RIN Access Tool's scope has been designed and approved by the CEC.

4 MCE Rates and Dynamic Rate Considerations

Adopted LMS Amendments Section 1623.1(a)(1) requests each large CCA to develop a plan that evaluates the cost-effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of dynamic rates for each customer class. After evaluating dynamic rates, the CCA may instead propose and evaluate specified programs and/or delay or modify its implementation of the LMS.

Adopted LMS Amendments Section 1623.1(b)(2) requests MCE apply to its rate-approving body for approval of at least one dynamic rate by July 1, 2025. The LMS state MCE is to apply for approval only of a dynamic rate only for those customer classes for which the Board determines such a rate will materially reduce peak load.

Adopted LMS Amendments Section 1623.1(b)(4) requests each CCA to offer to each of its electricity customers voluntary participation in either a dynamic rate developed according to Section 1623.1(b)(2), if such rate is approved by the Board, or a cost-effective load flexibility

program that allows automated response to MIDAS signals for each customer class the Board determines such a program would materially reduce peak load July 1, 2027.

This section provides an overview of MCE's current time-dependent rates and its plan to evaluate and develop dynamic rates as stated in the LMS.

4.1 Overview of MCE's Current Time-Dependent Rate Offerings

MCE currently offers several options for time-dependent or Time-Of-Use ("TOU") pricing, consistent with the options available to the broader PG&E service area. Approximately 66 percent of MCE households are on time-dependent rates. Current residential rate options are displayed in the table below.

Table 2: Current MCE Residential Rate Offerings[7]

MCE Residential Rate	Description of Rate Periods
E-1	Flat Rate Pricing, not time dependent
E-TOU-C - Default Time-of-Use	Utilizes 4pm-9pm peak rates every day
E-TOU-D - Time-of-Use	Utilizes 5pm-9pm peak rates on non-holiday weekdays only
ELEC - Time-of-Use for Qualified Electric Technologies	Utilizes lower rates from 12am-3pm
EV2 - Time-of-Use for Electric Vehicles	Utilizes lower rates from 12am-3pm

Additionally, MCE continues to provide limited service to legacy residential rate schedules that are no longer available to new customers:

- E-TOU-B - Time-of-Use: Utilizes 4pm-9pm peak rates on non-holiday weekdays only; and
- EV - Time-of-Use for Solar Customers with Electric Vehicles: Utilizes lower rates from 11pm-2pm.

MCE also offers a wide range of options for time-dependent pricing for non-residential customers as depicted in Table 3 below. Except in rare circumstances like street lighting, non-residential service is entirely billed according to time-dependent pricing. All of MCE's non-residential rates have 4pm-9pm daily peak and seasonal rates, except where noted otherwise.

[7] A complete list of MCE Residential rates can be found at https://www.mcecleanenergy.org/rates/.

Table 3: Current MCE Non-Residential Rate Offerings[8]

MCE Non-Residential Rates	Description of Rate Periods
B-1 - Small General Service	Utilizes six TOU periods (three in the Summer and three in the Winter)
B-1ST - Small General Service Plus Storage	Utilizes seven TOU periods (three in the Summer and four in the Winter)
B-6 - Small General Service	Utilizes five TOU periods (two in the Summer and three in the Winter) and stronger pricing signals relative to rate schedule B-1
B-10 - Medium General Service	Utilizes six TOU periods (three in the Summer and three in the Winter) and three voltage levels with discrete rates
B-19 - Medium General Service	Utilizes six TOU periods (three in the Summer and three in the Winter), TOU and seasonal based demand charges, and three voltage levels with discrete rates
B-19 Option R - Medium General Service for Solar	Utilizes six TOU periods (three in the Summer and three in the Winter), no demand charges, and three voltage levels with discrete rates
B-20 Option R - Large General Service for Solar	Utilizes six TOU periods (three in the Summer and three in the Winter), no demand charges, and three voltage levels with discrete rates
BEV - Commercial EV Charging	Utilizes three TOU periods, no seasonality, and three voltage levels with discrete rates
AG-A - Small Agriculture	Utilizes four TOU periods (two in the Summer and two in the Winter), and uses a 5pm-8pm peak pricing period
AG-B - Medium Agriculture	Utilizes four TOU periods (two in the Summer and two in the Winter), 5pm-8pm peak pricing period

[8] A complete list of MCE Non-Residential rates can be found at https://www.mcecleanenergy.org/commercial-rates/.

MCE Non-Residential Rates	Description of Rate Periods
AG-C - Large Agriculture	Utilizes four TOU periods (two in the Summer and two in the Winter), 5p-8p peak, summer peak demand
AG-F - Flexible TOU Agriculture	Utilizes AG-A/AG-B/AG-C variations as above, with two designated 24-hour off-peak days
SB - Standby Service	Utilizes six TOU periods (three in the Summer and three in the Winter), a reservation charge per kW, and three voltage levels with discrete rates
SL-1 - Street, Highway, and Outdoor Lighting	This rate is not time dependent
TC-1 - Traffic Control Service	This rate is not time dependent

MCE also continues to offer limited service to legacy non-residential rate schedules without a 4pm-9pm peak. Eligibility is determined by PG&E according to tariffs approved by the CPUC. These rates have a 12pm-6pm peak and seasonal rates, except where otherwise noted, and have weak pricing signals and are of limited significance to MCE's portfolio. Only 6.5 percent of MCE customers – almost entirely small commercial accounts – are served by these rates.

Table 4: MCE Legacy Rates

MCE Legacy Rates	Description of Rate Periods
A-1 - Small General Service	This is a non-TOU rate
A-1X - Small General Service	Utilizes five TOU periods (three in the Summer and two in the Winter)
A-6 - Small General Service	Utilizes five TOU periods (three in the Summer and two in the Winter)
A-10 - Medium General Service	This is a non-TOU rate but includes three voltage levels with discrete rates
A-10X - Medium General Service	Utilizes five TOU periods (three in the Summer and two in the Winter) and three voltage levels with discrete rates

MCE Legacy Rates	Description of Rate Periods
E-19 - Medium General Service	Utilizes five TOU periods (three in the Summer and two in the Winter), demand charges, and three voltage levels with discrete rates
E-20 - Large General Service	Utilizes five TOU periods (three in the Summer and two in the Winter), and three voltage levels with discrete rates
E-20 Option R - Large General Service for Solar Customers	Utilizes five TOU periods (three in the Summer and two in the Winter), and three voltage levels with discrete rates
AG-1 - Small Agricultural Service	This is a non-TOU rate
AG-4-A - Time-of-Use Agricultural Service	Time-of-Use Agricultural Service: Includes four TOU periods (two in the Summer and two in the Winter) and a connected load charge
AG-4-B - Time-of-Use Agricultural Service	Utilizes four TOU periods (two in the Summer and two in the Winter) and a maximum demand charge
AG-4-C - Time-of-Use Agricultural Service	Utilizes five TOU periods (three in the Summer and two in the Winter) and a peak demand charge
AG-5-A - Time-of-Use Agricultural Service	Utilizes four TOU periods (two in the Summer and two in the Winter) and a connected load charge
AG-5-B - Time-of-Use Agricultural Service	Utilizes four TOU periods (two in the Summer and two in the Winter) and a maximum demand charge
AG-5-C - Time-of-Use Agricultural Service	Utilizes five TOU periods (three in the Summer and two in the Winter) and a peak demand charge
AG-R - Time-of-Use Agricultural Service with Off Peak Days	Utilizes four TOU periods (two in the Summer and two in the Winter), two day-of-week options, two service levels, and connected load or demand charges

MCE Legacy Rates	Description of Rate Periods
AG-R - Time-of-Use Agricultural Service with Variable Peak	Utilizes four TOU periods (three in the Summer and two in the Winter), three peak hour options, two service levels, and connected load or demand charges
S - Standby Service	Utilizes five TOU periods (three in the Summer and two in the Winter), reservation charge per kW, and three voltage levels with discrete rates

MCE also offers two energy supply programs that are charged or credited to the customer's energy bill but separate from each customer's electric rate schedule:

- Deep Green Service: This program allows customers to choose 100 percent renewable energy content and includes a $0.01/kWh flat adder to all rates.
- Disadvantaged Communities Green Tariff ("DAC-GT"): This program allows eligible customers in disadvantaged communities to choose 100 percent renewable energy content and receive a 20 percent total bill discount.

4.2 Dynamic Rates Evaluation

MCE strongly appreciates and supports the LMS' goals to help encourage customers to shift energy consumption away from peak periods to minimize costs, improve reliability, and better align renewable energy supply and demand. MCE also agrees that two tools that can be utilized to encourage such a shift are flexible rate designs and automation technology.

Consistent with the adopted LMS, in this section MCE outlines its plan to evaluate future dynamic marginal cost-based rate offerings for its customers and provides an initial evaluation of the cost-effectiveness, equity, technological feasibility, and benefits of dynamic rates.

As a CCA, MCE's Board has sole authority over its customers' generation rate component and no other entity, including the CEC or CPUC, has the authority to set generation rates for MCE customers. Similarly, this means that MCE does not have authority to determine the distribution or transmission rate components of its customers. Any distribution and transmission rate components charged to MCE customers are determined and charged by PG&E, as approved by the CPUC and/or Federal Energy Regulatory Commission. As such, any dynamic or hourly rates adopted by MCE's Board will be generation-only. MCE and its Board cannot take responsibility for, or be required to calculate, rates for components that it has no control over such as distribution and transmission rate components.

While MCE has not yet offered any dynamic rates or dynamic rate pilots, MCE understands that there may be value in such rates and is currently evaluating whether it may offer one of the

dynamic rate pilots approved by the CPUC for PG&E's service area[9] or whether it may propose its own, distinct dynamic rate pilot(s) to its customers, which would allow MCE to collect the data necessary to evaluate the cost-effectiveness, equity, feasibility, and customer and grid benefits of such rates to inform MCE's future rate designs and offerings. Generally, MCE notes that it has a preference to create and offer MCE specific rates, pilots, and programs that can be uniquely tailored and administered by MCE to meet the needs of its customers, which may be distinct from other regions of PG&E's service area and rely on MCE's significantly clean and GHG-free portfolio in the California Independent System Operator markets.

In evaluating whether to offer future dynamic rates and/or pilots, MCE plans to evaluate portfolio-based cost-effectiveness, technical feasibility, equity, and benefits to MCE and its customers and the environment. MCE will consider what pricing options, if any, offer cost-effective and material, incremental, benefits over current rate and load flexibility offerings. Potential dynamic rate pilots should provide necessary and useful data to evaluate and determine the appropriateness (and potential design) of future dynamic rate offerings in MCE's service area.

As discussed below MCE does not at this time have sufficient evidence to conclude that developing and implementing dynamic rates in MCE's service area on the timeline outlined in the LMS would be cost effective or provide material incremental reductions to peak load beyond those of its current rate and programs portfolio for any customer class. As such MCE cannot currently commit to creating such a rate for Board approval by July 1, 2025. However, MCE is interested in collecting the data necessary to make such determinations and is exploring options to offer dynamic rate pilots in its service territory. MCE therefore recommends the Board find it necessary to modify Section 1623.1(b)(2)'s request for MCE to apply for approval of a dynamic rate by July 1, 2025. MCE recommends the Board conclude that the timeline must be modified to ensure cost-effective implementation and determine that MCE Staff may, but is not required to, propose such a rate to the Board by the target date of July 1, 2025. MCE will provide updates to its Board in its next plan iteration and any annual reports.

a. Cost-Effectiveness

In determining whether to offer dynamic rates that vary at least hourly as outlined in the LMS, one evaluation factor that MCE will consider is cost-effectiveness.

MCE notes that the CEC's adopted LMS state there shall be no reimbursement to local government agencies for the costs of carrying out the Standards as the Commission has found them to be cost effective, noting that savings realized will outweigh the costs associated with implementing the programs.[10] While MCE appreciates the plain language of the LMS, MCE disagrees that the cost-effectiveness of any rates or programs could be determined before those rates or programs actually exist. At this point there exists no evidence to conclude that MCE will

[9] For example, California Public Utilities Commission Decision (D) 24-01-032 approved the expansion of two demand flexibility pilots in PG&E's service area that would allow CCA participation. MCE is currently evaluating whether it may participate beginning in the Summer of 2025.

[10] CEC Load Management Standards Section 1623.1(e).

realize any net savings from implementing the LMS. MCE has not yet offered any hourly or dynamic rates or pilot programs to allow for sufficient analysis of the effectiveness (cost or otherwise) of dynamic rates in its service area. MCE has so far incurred only costs associated with the LMS and any benefits remain to be realized.

Nonetheless, MCE shares many of the CEC's stated goals in developing the LMS and is committed to encouraging customers to shift energy consumption to off-peak periods. MCE appreciates and understands that there may be significant value in dynamic rates and is interested in collecting the necessary information and data to determine if, and under what conditions, dynamic rates would be cost effective for MCE and its customers.

At present, MCE is exploring the possibility of creating an hourly rate pilot for its electric vehicle ("EV") customers, as well as monitoring and evaluating the status of CPUC approved PG&E rate pilots and considering participation for Summer 2025. However, without such primary data, MCE cannot at this time determine that such a rate or program will provide material incremental reductions to peak load or be cost effective for any customer class.

Significant uncertainties remain in both the cost to develop and the value MCE can reliably realize from implementing hourly rates. MCE anticipates that developing dynamic rates may result in significant costs and MCE's ability to realize the value of such rates will be determined by unknown factors like customer adoption and incremental response levels. Without robust pilot results in MCE's and PG&E's service area to perform a comprehensive analysis, MCE cannot accurately estimate development costs, the estimated total benefits, or whether those benefits would be likely to offset the costs for any customer class. Accordingly, MCE recommends the Board not require MCE to propose dynamic rate to its Board by the target date of July 1, 2025. MCE recommends the Board find that MCE may, but is not required to, propose such a rate by the target date.

MCE will continue to evaluate whether to offer dynamic rate pilots and rates to its customers and will evaluate the results of any pilots in PG&E's service area. To the extent MCE does participate in or offer dynamic rate pilots, MCE will use the pilot(s) as an opportunity to collect the data necessary to conduct its own cost-effectiveness analysis with MCE specific data, which would be used to inform future rate and program offerings as well as future iterations of MCE's LMS Plan.

In conducting such a future cost-effectiveness analysis, MCE expects to compare the benefits of the rate offering with costs of implementation. Estimated costs include but are not limited to rate development, rate and program administration, and technology costs. Estimated benefits include, but are not limited to, lower energy costs, increased load reduction, avoided energy and capacity costs, and reliability benefits. To demonstrate cost-effectiveness, the expected benefits for each rate must exceed the costs of implementation. MCE looks forward to providing updates to its Board, the CEC, and other interested parties as it moves forward.

b. Equity

Similarly to cost-effectiveness, MCE currently has no primary data sources to quantitatively speak to the equity component of offering hourly rates to its customers. MCE is committed to increasing equitable and affordable access to clean energy for its customers. While reductions

in peak demand provide grid benefits to all customers and those benefits could theoretically lower power procurement costs to all customers, currently there is not clear evidence that all MCE customers will benefit from lower rates. As MCE begins to evaluate whether to offer hourly rates to all customers, several equity components will be considered including:

Equitable Access to Automation and Benefits

Customers' ability to benefit from highly differentiated rates is directly linked to their ability to respond to those rates. Customers that can automate portions of their load will be best equipped to respond to pricing signals and benefit through lower energy bills or performance-based payments. Therefore, equitable access to automation devices and technology will be critical in ensuring that all customers can benefit from these rates. As such, MCE Staff believes it is appropriate to explore ways to ensure that customers on dynamic rates can access automation technology in an equitable manner. MCE may therefore explore offering additional incentives to provide automation technology for low-income customers and/or those who live in disadvantaged communities or multi-family properties who may otherwise not be able to benefit from automated load shifting programs or dynamic rates.

Cost Shifting

Assuming any change in rate design is designed to collect the same total level of revenue from all customers (i.e. revenue requirement), any change to rate design or structure means that some customers will pay less and some customers will pay more – without any changes to their behavior.[11] This mathematical reality is often referred to as a cost shift, as costs are shifted from one group of ratepayers to another. When rate offerings are voluntary, or opt-in, there is a greater risk that customers will simply choose the rate which allows them to pay less without making any changes to their behavior. These customers who can elect to participate in a rate that will lower their costs (and shift costs to other customers within their class) without any changes in behavior can be referred to as structural benefactors.

In developing dynamic rates with the goal of encouraging customers to *change* their behavior and shift their energy consumption away from peak hours, one of MCE's goals will be to minimize the amount of cost shifting that occurs between customers, particularly due to structural benefactors. To do so, MCE will aim to ensure that customers on hourly rates are sufficiently able to respond to price signals, whether through automation and/or price signals that are strong enough to incent behavioral change.

Customer Location

With few exceptions, customers do not choose where they are located on the electrical grid. It is partly because of this fact that grid infrastructure and energy costs have historically been spread, or averaged, across all customers. For example, rural customers have not been charged different prices for energy than city dwelling customers and MCE customers in Concord have not paid more than MCE customers in San Rafael, despite the potential differences in costs to serve those customers at any point in time (for example, due to local grid constraints). With a move to dynamic rates and advances in technology, it may be possible to charge customers in the same

[11] This is at least true in the short-term. However, in the long-term material reductions/changes in behavior may lower the total revenue requirement and those cost savings could be passed through to all customers.

rate class and on the same tariff at different rates at any point in time given their location on the grid.

In both the CEC's LMS Rulemaking and the CPUC's Demand Flexibility Proceeding, there has been discussion on the level of locational granularity that should be applied to hourly or sub-hourly rates. While MCE and others are likely to first utilize hourly rates that do not vary at a level more granular than the Default Load Aggregation Point, there has been discussion of rates that vary at more granular levels, such the circuit or transformer level. Essentially, this means that the level of local grid constraint can affect the rates a customer in that area pays for electricity. MCE believes this is an important equity concern that cannot be overlooked.

Local grid constraints vary based on grid infrastructure, design, and capacity constraints that are generally outside of any individual customer's control. The more locational granularity in rates, the more potential there is for equity issues to arise. To address this issue, evaluation should be done to ensure that dynamic pricing based on localized grid constraints does not particularly burden low-income residents or those in disadvantaged communities. MCE does not currently have data on how more granular locational variation in rates may impact equity but urges all California LSEs as well as the CEC and CPUC to work to ensure that certain customers are not unfairly harmed by future rate design simply due to their location on the grid.

c. Technological Feasibility

MCE expects that it is technically feasible to offer a dynamic hourly generation rate option by July 1, 2027, as outlined in the LMS, contingent upon PG&E providing revenue quality billing data to MCE on an hourly level or developing a reliable workaround. Current PG&E billing transactions do not include the hourly interval data which would be matched against hourly dynamic prices. MCE hopes that as PG&E develops CPUC approved hourly pricing pilots, this data will become available.

MCE notes that even if dynamic rates are technically feasible, daily rate uploads to MIDAS will need to be supported by the development of new systems, which may delay or otherwise impede offering dynamic rates in the near term. The limitations of the current MIDAS system and the lack of funding for LSEs to develop systems for interacting with MIDAS may mean that it will not be cost effective or feasible to maintain dynamic rates in MIDAS at this time.

d. Benefits to the Grid and Customers

MCE will also consider benefits to the grid and benefits to customers in its evaluation of dynamic rates. Assuming material changes in energy consumption behavior by customers, potential grid benefits resulting from hourly rates include but are not limited to reliability benefits, deferred, and reduced grid infrastructure investments, and environmental benefits.

Potential direct customer benefits include, but are not limited to, lower energy expenditures, reliability benefits, and theoretically lower rates – assuming material reductions to peak load that result in lower overall energy costs and reduced capacity and compliance costs. MCE does not currently have the data to quantify benefits to the grid and customers resulting from offering

hourly rates in its service territory. MCE plans to continue to gather data on this topic and will update this section in future iterations of its plan and annual reports.

4.3 Dynamic Rate Development and Application Plan

Adopted LMS Amendments Section 1623.1(b)(2) of the LMS requests MCE and other Large CCAs apply to its rate-approving body for approval of at least one dynamic rate by July 1, 2025. The LMS state MCE should apply for approval of a dynamic rate only for those customer classes for which the Board determines such a rate will materially reduce peak load. This section outlines how MCE plans to work toward this goal.

MCE has been, and plans to remain, actively engaged in dynamic rates discussions and proceedings at the CPUC and CEC. To date, MCE has committed considerable staff time, which amounts to significant and material cost to MCE, to these efforts, including making staff available to attend all noticed CEC LMS working group meetings and engaging in the CPUC's Demand Flexibility proceeding. Additionally, MCE is conducting research internally and in collaboration with external partners on how it might best design and offer dynamic rates in the future.

MCE is committed to exploring options for offering dynamic rate offerings to customers, but at this time cannot determine that such rates would provide material incremental reductions to peak load, provide other material benefits to MCE or its customers, or be cost effective for any customer class. In evaluating future potential dynamic rates MCE will consider whether or how any dynamic rate is expected to: 1) drive behavioral change; 2) be cost effective; 3) impact equity outcomes; and 4) provide reliable incremental benefits relative to MCE's current rate offerings.

At present, MCE is exploring the possibility of offering a dynamic rate pilot for its electric vehicle ("EV") customers, as well as monitoring and evaluating the status of CPUC approved PG&E rate pilots and considering participation for Summer 2025. However, without such primary data, MCE cannot at this time determine that such a rate or program will provide material incremental reductions to peak load or be cost effective for any customer class.

Significant uncertainties remain in both the cost to develop and the value MCE can reliably realize from implementing hourly rates. MCE anticipates that developing dynamic rates may result in significant costs and MCE's ability to realize the value of such rates will be determined by unknown factors like customer adoption and incremental load shifting response levels. Without robust pilot results in MCE's and PG&E's service area to perform a comprehensive analysis, MCE cannot accurately estimate development costs, the estimated total benefits, or whether those benefits would be likely to offset the costs. Accordingly, MCE recommends the Board not require MCE to propose a dynamic, hourly marginal cost-based rate, to its Board by the target date of July 1, 2025. MCE recommends the Board modify the request in LMS Section 1623.1(b)(2) that MCE propose dynamic rates by July 1, 2025, and declare that MCE may, but is not required to, propose such a rate to the Board for approval by July 1, 2025.

MCE will continue to evaluate if and how it may offer dynamic rates to its customers and will provide updates to its Board in its next plan iteration and any annual reports, and looks forward to continuing conversation and collaboration with stakeholders on possible pilot design, including how best to collect data that will effectively illustrate the costs and benefits of different dynamic rate structures and incorporate rates into MIDAS.

Additionally, LMS Section 1623.1(b)(4) requests MCE offer customers voluntary participation in either a dynamic rate, if approved by the Board, or a cost-effective load flexibility program by July 1, 2027. MCE notes that its offerings as of July 1, 2027, cannot be known at present, and the future timeline for deployment of future rate and program offerings will be dependent on future Board guidance and approval.

MCE plans to continue to provide updates to its Board as well as the CEC, as outlined in the LMS, and will further address the details of rate design and infrastructure needs as they become available.

5 Load Flexibility Programs

Adopted LMS Amendments Section 1623.1(b)(3) of the LMS requests MCE submit a list of cost-effective load flexibility programs to the CEC Executive Director by October 1, 2024. The portfolio of load flexibility programs is to provide at least one option to automate response to MIDAS signals for every customer class where such a program is determined by the Board to materially reduce peak load. If MCE's Board does not approve of and offer dynamic rates by July 1, 2027, the Standards state that MCE can meet the goals of the LMS by offering voluntary participation in a cost-effective MIDAS-integrated load flexibility program.

This section of MCE's Plan provides an overview of MCE's current load flexibility programs and addresses how MCE will evaluate and propose specified programs on the timeframes set forth in the LMS.

5.1 Overview of MCE Load Flexibility Programs

Residential Programs

MCE Sync

MCE Sync is an MCE-funded Automated Load Management program that utilizes a smart charging app to reduce EV owner's charging load during peak times, while also seeking to align EV charging load with high-solar daytime hours.[12] MCE began offering MCE Sync to eligible customers in 2021 and the program offers customers a flat monthly credit for participating in events.

Through 2023, MCE Sync had approximately 2,200 enrolled MCE customers who charge their EVs at home via a software platform which delivers direct load control of EV charging using vehicle telematics and networked electric vehicle supply equipment. To date, the program has shifted 90 percent of EV charging events out of the 4 pm – 9 pm window. An analysis of program data through May 2022 showed that customers saved an average of $10 shifting charging to off-peak hours.

MCE Sync does not currently have rates associated with events. MCE Staff are currently exploring the possibility of expanding the program in MCE's service area, including integrating dynamic pricing elements into future program offerings.

[12] *See* https://www.mcecleanenergy.org/mce-sync/.

Peak FLEXmarket

MCE's Peak FLEXmarket program is a market-driven demand flexibility program that assigns an hourly value to measured, behind-the-meter ("BTM") impacts.[13] Peak FLEXmarket is aimed at shifting load away from peak periods and provides customers with direct payments for measured load shedding or shifting during events, based on deviations from their individual baseline.

Peak FLEXmarket has successfully engaged new aggregators who have not participated in demand response, as well as program partners who have traditionally been confined to energy efficiency project development by presenting a value proposition for load flexibility. This program is a framework with the tools to measure and value hourly reductions in energy use and is technology agnostic.

Richmond Virtual Power Plant (VPP) Pilot

MCE is working to launch an innovative VPP pilot in Richmond, California, which will provide bill savings and increase local grid reliability, safety, and efficiency for low-income residents as part of Richmond's Advanced Energy Community project.[14] The VPP pilot includes $8 million in funding from the CEC and will provide a suite of clean distributed energy resources ("DERs") targeting low-income households in Richmond for dispatchability, flexibility, and resiliency purposes.

MCE's Richmond VPP Pilot is expected to provide significant bill savings for customers and significant local and grid benefits. MCE currently expects the pilot to launch in 2025.

Residential Efficiency Market

MCE's Residential Efficiency Market program is focused on incentivizing customers to install measures that can help reduce peak load.[15] Customers can receive a 20 percent upfront cash payment for the forecasted value of their energy efficiency projects and additional payments for metered savings of those energy efficiency projects.

Solar Storage Credit

MCE's Solar Storge Credit program is aimed at encouraging customers to discharge their energy storage systems from 4-9pm daily.[16] To be eligible for the credit, customers must be enrolled in a time-of-use rate, automate their battery to discharge from 4-9 p.m. daily and set their battery reserve to no more than 20 percent, except when preparing for or during a power outage. Customers are eligible to receive up to $20/month for participation based on their solar system's size.

[13] *See* https://www.mcecleanenergy.org/peak-flexmarket/.
[14] *See* http://mcecleanenergy.org/vpp.
[15] *See* https://www.mcecleanenergy.org/flexmarket/.
[16] *See* https://www.mcecleanenergy.org/solar-storage-credit/.

Nonresidential Programs

Peak FLEXmarket

MCE's Peak FLEXmarket program is a market-driven demand flexibility program that assigns an hourly value to measured BTM impacts. Peak FLEXmarket is aimed at shifting load away from peak periods and provides customers with direct payments for measured load shedding or shifting during events, based on deviations from their individual baseline.

Peak FLEXmarket has successfully engaged new aggregators who have not participated in demand response, as well as program partners who have traditionally been confined to energy efficiency project development by presenting a value proposition for load flexibility. This program is a framework with the tools to measure and value hourly reductions in energy use and is technology agnostic.

Commercial Efficiency Market

MCE's Commercial Efficiency Market program is focused on incentivizing non-residential customers to install measures that can help reduce peak load.[17] Customers can receive a 20 percent upfront cash payment for the forecasted value of their energy efficiency projects and additional payments for metered savings of those energy efficiency projects.

5.2 Evaluation of Programs

This section evaluates the cost-effectiveness, equity, technological feasibility, and benefits to the grid and customers of implementing programs that enable automated response to MIDAS signals. As discussed below, MCE cannot currently conclude that creating a new, or modifying an existing, load-modifying program to allow automated responses to MIDAS signals would be cost effective or offer material incremental benefit, such as material incremental peak load reduction, for any customer class.

Accordingly, MCE will continue to offer voluntary participation in its existing and future load flexibility programs. MCE will continue to consider the cost-effectiveness and peak load reduction potential of programs that enable automated response to MIDAS signals. To the extent that MCE's Board does not approve a dynamic rate offering by 2027, *and* MCE is at that time able to determine that modifying an existing program or creating a new program that enables automated response to MIDAS signals is cost effective and provides material incremental reductions to peak load for at least one customer class, MCE may at that time integrate a load-modifying program into MIDAS.

MCE will therefore submit to the CEC a list of load-modifying programs deemed cost-effective by October 1, 2024, but recommends the Board find that MCE is not required to include a program that allows automated response to MIDAS signals as it cannot determine such a program would be cost effective or produce material reductions to peak load for any customer class.

[17] *See* https://www.mcecleanenergy.org/flexmarket/.

5.2.1 Cost Effectiveness

As outlined by section 1623.1(b)(3) of the LMS, MCE will provide a list of load-modifying programs deemed cost effective to the CEC by October 1, 2024. At present, MCE expects that the list of cost-effective programs will include the following MCE load-modifying programs:

1. Peak FLEXmarket;
2. Commercial Efficiency Market; and
3. Residential Efficiency Market.

These programs are funded by ratepayers through MCE's Energy Efficiency Portfolio as authorized by the CPUC. To receive ratepayer funding, the CPUC requires MCE to demonstrate its energy efficiency portfolio is cost effective using CPUC-approved cost-effectiveness criteria.

As it relates to the cost-effectiveness of MCE's current and future self-funded and/or grant-funded load-modifying programs (MCE Sync, Solar Storage Credit, Richmond VPP Pilot, etc.) MCE has not yet evaluated these programs for cost-effectiveness in the same manner as its ratepayer funded energy efficiency programs. Generally, MCE notes that cost-effectiveness is just one measure used to determine whether to offer a program and is not necessarily a determining factor. For example, programs that are focused on providing equity benefits may not be cost-effective utilizing traditional cost-effectiveness evaluation criteria, but still provide significant benefit to certain customer segments and society at large. MCE may robustly evaluate these programs for cost-effectiveness in the future when evaluating the effectiveness of the programs, and as it makes future determinations on program offerings.

MCE does not currently expect to utilize program offerings with automated responses to MIDAS signals; however, if MCE's Board does not adopt an hourly rate by July 1, 2027, MCE may then evaluate whether there is an opportunity to create a new program or modify an existing program to allow responses to MIDAS signals. In doing so, MCE would look at the incremental value of each option, and if modifying an existing, or creating a new, program is deemed cost-effective and found to provide material reductions to peak load may elect to do so at that time.

MCE cannot currently conclude that the modification of current or development of new programs that allow for automated responses to dynamic price signals would be cost effective for any customer class. Developing new programs or modifying existing programs would require MCE to incur costs associated with design and implementation, along with new technology costs. While these costs could potentially be offset with capacity or energy cost savings, the magnitude of those benefits is uncertain.

In conducting future cost-effectiveness analyses, MCE would compare expected program benefits to expected costs of program design and implementation. Assuming incremental load shift that can be attributed to the program, expected benefits of a new load flexibility program that allows for automated response to MIDAS signals may include, but are not limited to, avoided energy and capacity costs, improved reliability, and environmental benefits. Expected costs may include, but are not limited to, program development costs, program administration costs, and technology and implementation costs.

5.2.2 Equity

MCE is committed to creating more equitable communities and providing equitable access to clean energy benefits throughout its service area. In choosing to modify or offer any program, MCE carefully considers equity impacts and has demonstrated its commitment to equitable program offerings since its inception. MCE aims to offer a suite of programs that provide customers with access to clean energy technology and services while lowering bills and greenhouse gas emissions. Some examples of MCE's commitment to equity include MCE's:

1. Income-qualified customer programs such as the Low-Income Families and Tenants Program, the MCE Cares Credit Program, DAC-GT program, and EV Rebate Program;
2. Commercial Equity Program;
3. Commitment to advancing supplier diversity and workforce development; and
4. MCE's Community Power Coalition.[18]

In evaluating any future load-modifying program offerings, MCE will plan to evaluate how that offering may impact customer equity. Potential evaluation criteria include, but are not limited to, equitable access to technology, direct customer benefits and bill impacts, and cost-shifting between and within rate classes. For example, most customers' ability to benefit from highly differentiated rates will be directly linked to their ability to respond to those rates. Customers that can automate portions of their load will be best equipped to respond and benefit. Therefore, equitable access to automation devices and technology will be critical in ensuring that all customers can benefit from load-modifying programs. To promote equitable access to automation technology MCE may explore providing additional incentives for low-income customers and/or those who located in disadvantaged communities or multi-family properties who may otherwise not be able to benefit from automated load shifting programs or dynamic rates.

5.2.3 Technological Feasibility

MCE is committed to offering load-modifying programs that encourage customers to shift their load away from periods of grid constraint and high greenhouse gas emissions. MCE strongly supports the LMS' goals to provide customers and their devices access to signals that may help automate their response to marginal signals such as prices and greenhouse gas signals to provide the greatest level of benefit for both the customer and the grid. MCE has demonstrated this support through the development of its MCE Sync EV charging mobile application and the MCE Peak FLEXmarket platform, both of which are technology platforms that help customers adjust their energy consumption through greater visibility. And while MCE believes it is technically feasible to offer customers programs that allow customers to respond to MIDAS signals, currently, both of these load-modifying programs are incompatible with the MIDAS

[18] More information on MCE's energy equity efforts can be found on its website at https://www.mcecleanenergy.org/energy-equity/#energyequity.

database, and MCE cannot conclude that modifying them to be compatible would be cost effective or result in material incremental load reduction:[19]

- MCE Sync - This program provides a flat monthly credit to customers for participating in events, and does not have rates associated with events, and thus would not support inclusion in MIDAS.
- PeakFLEX Market - There is currently no way for MIDAS to show customers their current real-time rate for this program, as it is based on separate prices (baseline and above-baseline) that depend on a customers' individual usage history, which is not a component of MIDAS.

As MCE's existing load-modifying programs are not currently technologically compatible with MIDAS, if MCE at a later date elects to work towards the goals of the LMS via a MIDAS enabled program offering MCE would need to determine how it could either integrate its existing programs with MIDAS or explore the creation of a new program that would be compatible with the current or future design of MIDAS. Such determinations will need to be made by the Board at a future date.

5.2.4 Benefits to the Grid and Customers

In considering whether to modify existing or offer new load-modifying programs, including those that allow automated response to MIDAS signals, MCE may consider benefits to the grid and customers.

Assuming incremental load shift or reduction that can be attributed to the program, potential grid benefits include reduced capacity costs (for example through lower Resource Adequacy costs), reduced of deferred transmission and distribution system upgrades, lower energy costs, increased reliability benefits, and environmental benefits.

Assuming incremental load shift or reduction that can be attributed to the program, potential customer benefits include pass-through energy cost savings from grid benefits as well as pass-through cost savings from potential reduced compliance costs for MCE, improved reliability, improved environmental benefits, and direct cost savings from participation in load-modifying programs.

All of these potential grid and customer benefits depend on the reliability and magnitude of load shift and reduction that load-modifying programs are able to achieve. MCE is at this time unable to conclude that future programs or modifications to existing programs to allow automated responses to MIDAS signals would result in material grid benefits relative to MCE's existing offerings or result in pass through savings to customers for any customer class. If MCE creates a load-modifying program that allows automated response to MIDAS signals in the future it will

[19] While not a load-modifying program, MCE also notes that its Disadvantaged Community Green Tariff program is also not included in MIDAS currently as it is not compatible with the current design of MIDAS. The 20 percent bill discount for the DAC-GT program is calculated from a customer's total billed charges, inclusive of non-volumetric and variable IOU charges, by reading the total charges from the previous bill. As such, MCE cannot generate a volumetric price inclusive of this discount.

aim to design the program in such a way to generate material benefits to the grid and MCE customers.

6 Public Information Program

Adopted LMS Amendments Section 1623.1(b)(5) of the LMS requests MCE and other Large CCAs to conduct a public information program to inform and educate affected customers on why dynamic rates or load flexibility programs and automation are needed, how they will be used, and how these rates and programs can save customers money.

MCE appreciates the LMS' intent to ensure that any load-modifying rates or programs developed are effectively marketed to customers with the aim of encouraging enrollment and maximizing customer success and grid benefits. As a local, community-based organization, MCE values and is deeply committed to providing quality customer and community communication, education, collaboration, and customer service.

As a general matter, all MCE rates and programs can be found on MCE's website. Any future dynamic rates or load-modifying programs will also be listed and described on its webpage.[20] MCE utilizes best practices to provide consistent and accurate communications and response support with its customers and communities. This includes utilizing various communication mediums including joint rate mailers, emails, direct mail, e-newsletters, press releases, webinars, social media posts, public presentations and event attendance and sponsorship throughout MCE's member communities. In 2023 alone, MCE attended more than 250 events in our service area and presented to 69 local community organizations and city councils. MCE plans to continue communication best practices to maintain its outreach, education, and marketing of rates, programs, and pilots that support load flexibility and recognize the benefits of reducing peak load and using energy during periods of higher renewables supply. In addition, MCE has developed an in-house service center to support and effectively respond to customer inquiries and further the education and benefits of load-modifying programs.

Historically, MCE has voluntarily utilized various types of marketing campaigns to drive enrollment and successful participation in rate and program offerings including those created for load-modifying purposes. For example, to encourage customers to shift load on Time-of-Use rates, MCE conducted a public information campaign that included direct mail, website updates, digital advertising, streaming, and radio placement encouraging customers to use less energy during the 4pm - 9pm peak period targeted to customers throughout MCE's service area.[21]

MCE notes that the LMS do not include a timeline for the public information campaign. As there is no timeline expressed in the Standards and MCE has not created or recommended Board approval of any new hourly marginal cost-based rates or programs that allow automated response to MIDAS signals, MCE does not have details on what future public information programs may entail. MCE expects that if dynamic rates or new load flexibility programs are

[20] MCE Residential rates can be viewed at https://www.mcecleanenergy.org/rates/. MCE Commercial rates can be viewed at https://www.mcecleanenergy.org/commercial-rates/. MCE program offerings can be found at https://www.mcecleanenergy.org/customer-programs/.
[21] *See* https://www.mcecleanenergy.org/4-9/.

adopted MCE would utilize a public information program to drive customer adoption, understanding, and success in said rates or programs.

At a minimum, MCE would expect the public information program to highlight how individual customers may be impacted (i.e. bill impacts) and how changes to their behavior can create grid and/or environmental benefits for all customers. This type of public information program would utilize some or all the following communication mediums: direct mail, email correspondence, website updates, social media posts, webinars, television/streaming commercials, press releases or news articles, and public presentations. MCE may also work with its community partners and/or program and technology partners to develop and deliver any public information programs.

MCE expects that any public information campaign would require incremental costs that are not currently accounted for, and MCE would need to factor these public information and response program costs and their recovery into any cost-effectiveness analysis and recommendation to its Board.

7 Appendix

Appendix A – MCE MIDAS Rate Identification Numbers

The below table displays the RINs associated with each of MCE's residential and non-residential rates and rate permutations that have been uploaded to MIDAS.

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-PBZD-0000	ETOUB	Deep Green
USCA-XXMC-PCZD-0000	ETOUC	Deep Green
USCA-XXMC-PDZD-0000	ETOUD	Deep Green
USCA-XXMC-OZZD-0000	ELEC	Deep Green
USCA-XXMC-QAZD-0000	EVA	Deep Green
USCA-XXMC-QUZD-0000	EV2	Deep Green
USCA-XXMC-AXZD-0000	A1X	Deep Green
USCA-XXMC-EZZD-0000	B1	Deep Green
USCA-XXMC-ETZD-0000	B1ST	Deep Green
USCA-XXMC-CZZD-0000	A6	Deep Green
USCA-XXMC-IZZD-0000	B6	Deep Green
USCA-XXMC-BXCD-0000	A10SX	Deep Green
USCA-XXMC-FZCD-0000	B10S	Deep Green
USCA-XXMC-BXBD-0000	A10PX	Deep Green
USCA-XXMC-FZBD-0000	B10P	Deep Green
USCA-XXMC-BXDD-0000	A10TX	Deep Green
USCA-XXMC-FZDD-0000	B10T	Deep Green
USCA-XXMC-LZCD-0000	E19S	Deep Green
USCA-XXMC-GZCD-0000	B19S	Deep Green
USCA-XXMC-LZBD-0000	E19P	Deep Green
USCA-XXMC-GZBD-0000	B19P	Deep Green
USCA-XXMC-LZDD-0000	E19T	Deep Green
USCA-XXMC-GZDD-0000	B19T	Deep Green
USCA-XXMC-LRCD-0000	E19SR	Deep Green
USCA-XXMC-GRCD-0000	B19SR	Deep Green
USCA-XXMC-LRBD-0000	E19PR	Deep Green
USCA-XXMC-GRBD-0000	B19PR	Deep Green
USCA-XXMC-LRDD-0000	E19TR	Deep Green
USCA-XXMC-GRDD-0000	B19TR	Deep Green
USCA-XXMC-MZCD-0000	E20S	Deep Green
USCA-XXMC-HZCD-0000	B20S	Deep Green
USCA-XXMC-MZBD-0000	E20P	Deep Green
USCA-XXMC-HZBD-0000	B20P	Deep Green

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-MZDD-0000	E20T	Deep Green
USCA-XXMC-HZDD-0000	B20T	Deep Green
USCA-XXMC-MRCD-0000	E20SR	Deep Green
USCA-XXMC-HRCD-0000	B20SR	Deep Green
USCA-XXMC-MRBD-0000	E20PR	Deep Green
USCA-XXMC-HRBD-0000	B20PR	Deep Green
USCA-XXMC-MRDD-0000	E20TR	Deep Green
USCA-XXMC-HRDD-0000	B20TR	Deep Green
USCA-XXMC-DAED-0000	AGA1	Deep Green
USCA-XXMC-DAFD-0000	AGA2	Deep Green
USCA-XXMC-DBZD-0000	AGB	Deep Green
USCA-XXMC-DCZD-0000	AGC	Deep Green
USCA-XXMC-DGED-0000	AGFA1	Deep Green
USCA-XXMC-DGFD-0000	AGFA2	Deep Green
USCA-XXMC-DGGD-0000	AGFA3	Deep Green
USCA-XXMC-DHED-0000	AGFB1	Deep Green
USCA-XXMC-DHFD-0000	AGFB2	Deep Green
USCA-XXMC-DHGD-0000	AGFB3	Deep Green
USCA-XXMC-DIED-0000	AGFC1	Deep Green
USCA-XXMC-DIFD-0000	AGFC2	Deep Green
USCA-XXMC-DIGD-0000	AGFC3	Deep Green
USCA-XXMC-DJZD-0000	AG4A	Deep Green
USCA-XXMC-DKZD-0000	AG4B	Deep Green
USCA-XXMC-DLZD-0000	AG4C	Deep Green
USCA-XXMC-DMZD-0000	AG5A	Deep Green
USCA-XXMC-DNZD-0000	AG5B	Deep Green
USCA-XXMC-DOZD-0000	AG5C	Deep Green
USCA-XXMC-TZCD-0000	STOUS	Deep Green
USCA-XXMC-TZBD-0000	STOUP	Deep Green
USCA-XXMC-TZDD-0000	STOUT	Deep Green
USCA-XXMC-SZCD-0000	SBS	Deep Green
USCA-XXMC-SZBD-0000	SBP	Deep Green
USCA-XXMC-SZDD-0000	SBT	Deep Green
USCA-XXMC-JZED-0000	BEV1	Deep Green
USCA-XXMC-JUCD-0000	BEV2S	Deep Green
USCA-XXMC-JUBD-0000	BEV2P	Deep Green
USCA-XXMC-NZZD-0000	E6	Deep Green
USCA-XXMC-PBZL-0000	ETOUB	Light Green
USCA-XXMC-PCZL-0000	ETOUC	Light Green
USCA-XXMC-PDZL-0000	ETOUD	Light Green
USCA-XXMC-OZZL-0000	ELEC	Light Green

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-QAZL-0000	EVA	Light Green
USCA-XXMC-QUZL-0000	EV2	Light Green
USCA-XXMC-AXZL-0000	A1X	Light Green
USCA-XXMC-EZZL-0000	B1	Light Green
USCA-XXMC-ETZL-0000	B1ST	Light Green
USCA-XXMC-CZZL-0000	A6	Light Green
USCA-XXMC-IZZL-0000	B6	Light Green
USCA-XXMC-BXCL-0000	A10SX	Light Green
USCA-XXMC-FZCL-0000	B10S	Light Green
USCA-XXMC-BXBL-0000	A10PX	Light Green
USCA-XXMC-FZBL-0000	B10P	Light Green
USCA-XXMC-BXDL-0000	A10TX	Light Green
USCA-XXMC-FZDL-0000	B10T	Light Green
USCA-XXMC-LZCL-0000	E19S	Light Green
USCA-XXMC-GZCL-0000	B19S	Light Green
USCA-XXMC-LZBL-0000	E19P	Light Green
USCA-XXMC-GZBL-0000	B19P	Light Green
USCA-XXMC-LZDL-0000	E19T	Light Green
USCA-XXMC-GZDL-0000	B19T	Light Green
USCA-XXMC-LRCL-0000	E19SR	Light Green
USCA-XXMC-GRCL-0000	B19SR	Light Green
USCA-XXMC-LRBL-0000	E19PR	Light Green
USCA-XXMC-GRBL-0000	B19PR	Light Green
USCA-XXMC-LRDL-0000	E19TR	Light Green
USCA-XXMC-GRDL-0000	B19TR	Light Green
USCA-XXMC-MZCL-0000	E20S	Light Green
USCA-XXMC-HZCL-0000	B20S	Light Green
USCA-XXMC-MZBL-0000	E20P	Light Green
USCA-XXMC-HZBL-0000	B20P	Light Green
USCA-XXMC-MZDL-0000	E20T	Light Green
USCA-XXMC-HZDL-0000	B20T	Light Green
USCA-XXMC-MRCL-0000	E20SR	Light Green
USCA-XXMC-HRCL-0000	B20SR	Light Green
USCA-XXMC-MRBL-0000	E20PR	Light Green
USCA-XXMC-HRBL-0000	B20PR	Light Green
USCA-XXMC-MRDL-0000	E20TR	Light Green
USCA-XXMC-HRDL-0000	B20TR	Light Green
USCA-XXMC-DAEL-0000	AGA1	Light Green
USCA-XXMC-DAFL-0000	AGA2	Light Green
USCA-XXMC-DBZL-0000	AGB	Light Green
USCA-XXMC-DCZL-0000	AGC	Light Green

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-DGEL-0000	AGFA1	Light Green
USCA-XXMC-DGFL-0000	AGFA2	Light Green
USCA-XXMC-DGGL-0000	AGFA3	Light Green
USCA-XXMC-DHEL-0000	AGFB1	Light Green
USCA-XXMC-DHFL-0000	AGFB2	Light Green
USCA-XXMC-DHGL-0000	AGFB3	Light Green
USCA-XXMC-DIEL-0000	AGFC1	Light Green
USCA-XXMC-DIFL-0000	AGFC2	Light Green
USCA-XXMC-DIGL-0000	AGFC3	Light Green
USCA-XXMC-DJZL-0000	AG4A	Light Green
USCA-XXMC-DKZL-0000	AG4B	Light Green
USCA-XXMC-DLZL-0000	AG4C	Light Green
USCA-XXMC-DMZL-0000	AG5A	Light Green
USCA-XXMC-DNZL-0000	AG5B	Light Green
USCA-XXMC-DOZL-0000	AG5C	Light Green
USCA-XXMC-TZCL-0000	STOUS	Light Green
USCA-XXMC-TZBL-0000	STOUP	Light Green
USCA-XXMC-TZDL-0000	STOUT	Light Green
USCA-XXMC-SZCL-0000	SBS	Light Green
USCA-XXMC-SZBL-0000	SBP	Light Green
USCA-XXMC-SZDL-0000	SBT	Light Green
USCA-XXMC-JZEL-0000	BEV1	Light Green
USCA-XXMC-JUCL-0000	BEV2S	Light Green
USCA-XXMC-JUBL-0000	BEV2P	Light Green
USCA-XXMC-NZZL-0000	E6	Light Green

May 16, 2024

TO: MCE Board of Directors

FROM: Sabrinna Soldavini, Manager of Policy

RE: Policy Update of Regulatory and Legislative Items

ATTACHMENT: Regulatory Packet with Filings since the March Board Meeting

Dear Board Members:

Below is a summary of the key activities at the state and federal legislatures and the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and the California Independent System Operator (CAISO) impacting Community Choice Aggregation (CCA) and MCE.

I. Legislative Advocacy

a. State Legislative Advocacy

The 2024 legislative session is in full swing. By the date of this Staff Report, all bills have been heard by the relevant policy committees in their house of origin, and those that were voted out of their policy committees are either teed up for consideration by the Appropriations Committee in their house of origin, or they have advanced to floor votes. MCE has taken support positions on the bills listed below. To date, MCE has not taken any formal oppose positions.

- SB 1130 (Bradford) - This bill will expand eligibility for the Family Electric Rate Assistance (FERA) program, which will help thousands more customers better afford their electric bills. FERA provides an 18% discount on electric bills for households of 3 or more people that earn between 200% - 250% of Federal Poverty Guidelines. This bill would expand FERA eligibility to households of 1-2 members, with the same income criteria.
- SB 1095 (Becker) - This bill will make it easier to electrify manufactured and mobile homes by adjusting some of the rules about appliances in those types of homes.

- SB 1221 (Min) - This bill will allow for neighborhood-scale electrification pilots in communities where the gas distribution system needs significant upgrades.
- AB 3062 (Bauer-Kahan) - This bill will require electric investor-owned utilities (IOUs) and public electric utilities to give at least 24 hours' notice to local fire protection districts when they plan to conduct controlled or prescribed burns for vegetation management. Assembly Member Bauer-Kahan is part of MCE's delegation, representing part of Contra Costa County.
- SB 1014 (Dodd) - This bill will promote better coordination and prioritization of wildfire risk reduction efforts among the IOUs; federal, state, local, and tribal governments; non-governmental organizations (NGOs); and other involved entities. This could reduce IOU spending on wildfire mitigation without increasing risk, which will promote affordability for all customers including MCE's. Senator Dodd is part of MCE's delegation, representing Napa County, Solano County, and part of Contra Costa County.

b. Federal Legislative Advocacy

In late March 2024, MCE staff participated in a Joint CCA Lobby Day in Washington, D.C., alongside 5 other California CCAs. MCE met individually with our House delegation and participated in joint meetings with staff for Senators Butler and Padilla, as well as the Department of Energy's State and Community Energy Programs division. MCE highlighted our Virtual Power Plant pilot, as well as our local renewable projects and building and transportation electrification programs. MCE also advocated for our three Community Project Spending proposals:

- $1.3 million for an Emergency Water Heater Loaner Program. A loaner program will allow customers who need emergency replacement of a broken gas water heater to use a loaner until they have completed any electrical or construction work needed to install a heat pump water heater.
- $1.5 million for eBike Access and Adoption. This program would support incentives for electric bicycles (eBikes), including cargo and adaptive bikes, and safety equipment like helmets, locks and lights. The program would also create at least four local community partnership agreements to support rider safety education.
- $1.3 million for a Restaurant Electrification Pilot. The pilot would support 10 restaurants in low income and environmental justice communities in converting their kitchens to electric equipment. The pilot would produce case studies including lessons learned and recommended best practices.

II. California Public Utilities Commission

a. Provider of Last Resort (POLR)

In April 2024, the CPUC approved a Decision in its POLR proceeding, aimed at updating Financial Security Requirements (FSR) and financial monitoring guidelines for CCAs. The

POLR is the utility required to provide service to customers in the rare event that a Load Serving Entity (LSE) is no longer able to serve its customers. Pacific Gas & Electric (PG&E) currently serves as the POLR for MCE customers. As a hedge against the theoretical risk of MCE needing to return all of its customers to the POLR, MCE is required to post an FSR with PG&E that could be drawn upon to cover the difference in the incremental costs and revenue generated by serving the returned customers.

As expected, the Decision does increase the minimum FSR, but importantly the Decision adopted numerous recommendations from MCE and the California Community Choice Association (CalCCA) that are expected to limit the financial impact to MCE and its customers and retain reasonable financial monitoring requirements. For example, the Decision adopted recommendations from CalCCA to account for the value of resource adequacy in the FSR calculation and to reject a proposal that would have required MCE to post a significantly higher FSR to cover two months of forward energy prices. The new FSR requirements are expected to be implemented later this year, and MCE will provide an update to the Board if there are any significant changes to expectations.

Fiscal Impact: The POLR Decision will require MCE to increase its minimum FSR posting from $147,000 to approximately $2.5 million. Fiscal impacts beyond the difference in the minimum posting are unknown and subject to future market conditions.

b. Income Graduated Fixed Charge (IGFC)

In March 2024, the CPUC issued a PD addressing the income graduated fixed charge (IGFC) required by Assembly Bill (AB) 205. If adopted, the PD would create a monthly fixed charge on the PG&E portion of all residential customer bills. The PD would create three tiers of IGFCs: (1) $6 per month for customers enrolled in CARE; (2) ~$12 per month for customers enrolled in FERA or in affordable housing restricted to residents at or below 80% of area median income; and (3) $24.15 per month for all other customers. If approved, the new bill structure would go into effect in late 2025 and early 2026. The IGFC will not impact the MCE portion of a customer's charges but will impact their overall monthly bill. Specific bill impacts will depend on the customer's usage level and their PG&E climate zone; however, MCE customers enrolled in CARE or FERA with average usage are expected to see monthly bill decreases and all other customers with average usage are expected to see monthly bill impacts ranging from a decrease of $1.47 per month to an increase of $9.11 per month.

In April 2024, CalCCA filed Opening Comments on the PD that focused on supporting the PD's exclusion of certain cost-categories such as the Power Charge Indifference Adjustment from the IGFC and elements of the PD that are aimed at ensuring CCAs valuable feedback is incorporated into marketing, education, and outreach efforts and implementation plans as they relate to the IGFC.

The CPUC is currently expected to vote on the PD at its May 9, 2024 voting meeting.

Fiscal Impact: There is no direct fiscal impact to MCE.

c. Integrated Resource Planning (IRP)

In April 2024, the CPUC issued an Amended Scoping Memo (Scoping Memo) in the IRP proceeding to modify the procedural schedule for the next compliance IRP cycle and add a number of important issues within the scope of the existing proceeding. These issues include implementation of AB 1373, which directs the CPUC to determine by September 1, 2024, whether to direct the Department of Water Resources (DWR) to procure long-lead-time resources (such as off-shore wind) on behalf of all LSEs to help meet the state's reliability and GHG requirements. Also added within the scope is development of the Reliable and Clean Power Procurement Program (RCPPP). The RCPPP, which was first broached in 2022, is the CPUC's attempt to design a more structured and methodical approach to the IRP process, LSE IRP compliance, and future mandated procurement. Both issues will require increased coordination with concurrent developments in the RA proceeding around near-term reliability, RA compliance accounting, and hourly Slice-of-Day framework.

The CPUC issued a ruling at the end of April requesting comment on AB 1373 implementation issues. The CPUC will work with stakeholders over the coming months to define the scale, scope, and need for any potential DWR procurement. The CPUC expects to issue a Proposed Decision in July and a Final Decision in August, in advance of the September 1 statutory deadline.

Regarding the RCPPP, the CPUC expects to issue an initial proposal this summer and work with stakeholders through the end of 2024 with a Final Decision expected in early 2025.

Given the large structural issues now under consideration in the IRP, the Scoping Memo also modifies the ordinary two-year IRP cycle for individual Load Serving Entities (LSE). To accommodate implementation of AB 1373 and the RCPPP, the next round of individual LSE compliance IRPs will be due November 1, 2025 instead of in 2024.

Fiscal Impact: There is no direct fiscal impact to MCE.

d. Energy Efficiency (EE)

On March 15, 2024 MCE filed a Tier 3 Advice Letter proposing details of its Integrated Demand Side Management (IDSM) program for 2024-2027 as part of its EE portfolio. In July 2023, the CPUC approved MCE's EE portfolio programs for 2024-2027 and allowed program administrators by March 15, 2024 to propose implementation of multi-distributed energy resource projects and receive rebates or incentives for non-EE IDSM measures through their portfolio programs. MCE proposed offering an updated version of its Peak Flex Market program that will offer a year-round, comprehensive strategy that

integrates demand response and load shifting strategies for both residential and commercial customers to redistribute daily energy use away from peak demand hours of 4pm – 9pm PST. The CPUC is reviewing MCE and other program administrators' IDSM advice letters and will subsequently issue a resolution on their merits.

Fiscal Impact: There is no direct fiscal impact to MCE. The CPUC already approved $4,000,000 in IDSM funding within its EE portfolio.

e. Disconnections

On April 15, 2024, MCE joined the Joint CCAs represented by CalCCA in filing opening comments in response to an ALJ ruling requesting input on the "waterfall" methodology of allocating arrearage payments. Prior to the COVID-19 pandemic, payments on past due balances were first applied to IOU charges, then to CCA charges. Recognizing the unfairness of this methodology, the CPUC determined that payments would instead be applied proportionally between past due IOU and CCA charges and that the matter would be revisited in September of 2024. MCE's opening comments emphasized the CPUC's past determination that the "waterfall" allocation unfairly disadvantaged CCAs and should be ended, as CCAs are in the public interest. In reply comments filed on May 3, 2024, the Joint CCAs reiterated that CCAs are in the public interest and are unfairly disadvantaged by the "waterfall" methodology.

Fiscal Impact: If the CPUC opts to maintain the proportional allocation, there will be no direct fiscal impact to MCE.

f. Green Access Programs

In March 2024, the CPUC issued a proposed decision in the Green Access Programs Application for Review. If adopted, the PD would (1) create a new community renewables program and a shared-subscription model, (2) expand capacity for and make programmatic changes to the Disadvantaged Communities Green Tariff (DAC-GT), and (3) end the Community Solar Green Tariff (CSGT) and roll unused capacity into DAC-GT. MCE joined the Joint CCAs in filing opening and reply comments, as well as participating in an ex parte meeting with the Office of President Reynolds. The Joint CCAs were generally supportive of the proposed changes to the DAC-GT program, as the PD accepted many proposals made by the Joint CCAs including expanding program capacity, enacting broader project siting requirements, and assessing automated billing. The Joint CCAs expressed the need for the proposed new community renewables program to allow interested CCAs to participate with their own tariffs, whether CCAs choose to use existing tariffs or adopt new tariffs for the program.

Fiscal Impact: If the CPUC adopts the PD, MCE will receive additional funding to procure new capacity for DAC-GT and serve more low-income customers with bill discounts.

III. California Independent System Operator (CAISO)

In April 2024, the CAISO released its Draft Transmission Plan (Draft TPP) to support California's need to add 85 GW of new capacity to the grid by 2035 by building out the transmission system. To achieve this goal, the Draft TPP identifies a need for 26 reliability- and policy-driven transmission projects at an estimated cost of $6.1 billion. In particular, the Draft TPP identifies several projects to integrate offshore wind in Northern California, representing a significant portion of the estimated costs (between $3.1-$4.5 billion).

In late April, MCE supported CalCCA's comments on the Draft TPP. CalCCA's comments recommend that given the significant costs associated with policy-driven projects like offshore wind, and that central procurement issues are currently being deliberated at the CPUC, the CAISO should establish a more flexible process for approving policy-driven projects identified in the Draft TPP to ensure that in the event that offshore wind does not get built as quickly as anticipated, these costly transmission investments will not become stranded assets.

The Draft TPP is expected to be considered by the CAISO Board in May. Staff will provide updates as they become available.

Fiscal Impact: The Draft TPP has no immediate fiscal impact on MCE, but ultimately the transmission projects approved and built will impact MCE's procurement efforts.

Recommendation: There are no recommended actions at this time.