CITY OF GOLETA

**Agenda Item E.2**
**DISCUSSION/ACTION ITEM**
**Meeting Date: July 16, 2019**

**TO:** Mayor and Councilmembers

**FROM:** Peter Imhof, Planning & Environmental Review Director

**CONTACT:** Cindy Moore, Sustainability Coordinator

**SUBJECT:** Community Choice Energy Feasibility Study Update

**RECOMMENDATION:**

A. Receive a report from staff on the results of the Santa Barbara County Community Choice Energy Feasibility Study Update by Pacific Energy Advisors; and

B. Provide direction to staff regarding preferred community choice energy (CCE) options.

**BACKGROUND:**

**Community Choice Energy**

Assembly Bill 117 was passed by the California Legislature in 2002 to establish Community Choice Aggregation (CCA), also known as Community Choice Energy (CCE). This law enables cities, counties and other authorized entities to aggregate electricity demand within their jurisdictions to purchase and/or generate electricity supplies for residents and businesses within their jurisdiction. The existing investor-owned utility (IOU) continues to provide for billing, physical transmission and distribution services. Southern California Edison (SCE) is the IOU in our region. The day-to-day experience for the customer is the same; the difference being that the energy is purchased through the CCE. The CCE model is an opt-out program, so all eligible customers are enrolled in the CCE's service upon the stated implementation date. Customers can opt out at any time and return back to bundled service with SCE.

CCEs are typically created to provide a higher percentage of renewable or carbon-free electricity, such as wind and solar, at competitive and lower rates than existing investor-owned utilities, while giving consumers local choices and promoting local economic development. Currently, there are nineteen CCE programs in operation throughout California, serving close to 10 million customers.[1]

[1] For a list of operational and in-development CCE programs, please visit https://cleanpowerexchange.org/california-community-choice/.

## Previous Community Choice Energy Feasibility Studies

### ➢ Tri-County Regional CCE Feasibility Study

In June 2015, the Santa Barbara County Board of Supervisors approved $400,000 to evaluate the formation of a CCE program. Ten jurisdictions and the Community Environmental Council joined the County of Santa Barbara in creating Central Coast Power, a consortium to fund a feasibility study to help determine whether CCE is a good fit for the Tri-County Region (Santa Barbara, Ventura and San Luis Obispo). The County formed an Advisory Working Group composed of representatives from cities and counties that contributed financially in order to help guide and oversee the feasibility analysis, provide outreach support, and monitor policy and program developments related to CCE. The City Council did not authorize a financial contribution for Advisory Working Group participation, but authorization for data sharing was provided.

Willdan Financial Services conducted the Tri-County CCE Feasibility Study, and MRW and Associates performed a peer review to evaluate the reasonableness of Willdan's findings. The results were released in September 2017 and indicated that a new regional CCE program spanning Santa Barbara, San Luis Obispo, and Ventura Counties, under the assumptions used in the feasibility study and peer review, was not likely to be able to offer competitive rates in SCE territory and remain a solvent organization.[2]

Following the presentation of the Tri-County Study results, the County of Ventura and many of its cities joined the Clean Power Alliance, an existing CCE program serving parts of Los Angeles and Ventura Counties. The County of San Luis Obispo discontinued its exploration of CCE and the City of San Luis Obispo and the City of Morro Bay have since joined Monterey Bay Community Power, the CCE program currently serving Monterey, San Benito, and Santa Cruz Counties.

In October 2017, the County Board of Supervisors directed County staff to assess the viability of CCE for all or part of Santa Barbara County. In December 2017, the Goleta City Council authorized participation in this additional feasibility assessment, consistent with the City's Climate Action Plan Measure No. CCA-1, which describes working with other agencies to create a framework for a CCE program. County staff subsequently engaged Pacific Energy Advisors, Inc. (PEA) to prepare the study, which was funded by the County, the Cities of Goleta, Carpinteria, and Santa Barbara, and the Community Environmental Council.

### ➢ Santa Barbara County CCE Feasibility Study

As part of the Santa Barbara County CCE Feasibility Study, PEA evaluated the viability of CCE for three geographic participation scenarios, including 1) All Santa Barbara County (unincorporated + incorporated cities), 2) Unincorporated Santa Barbara County Only, and 3) City of Santa Barbara Only. For each geographic scenario, PEA evaluated

[2] To review the Tri-County CCE Feasibility Study, please visit: http://www.centralcoastpower.org/resources.nrg#fasibility

total program costs, rate competitiveness, and financial position for three electricity supply scenarios over an 11-year study period.

As part of its analysis, PEA built two indicative electricity supply scenarios (one for customers in Pacific Gas and Electric (PG&E) territory and another for SCE territory) to illustrate how a potential CCE program's electricity mix might compare to the IOUs' portfolios. PEA concluded that any of the three geographic scenarios could offer cleaner electricity at a comparable rate to PG&E or SCE, as applicable. For each geographic scenario, the costs, and therefore rates, increased with higher renewable energy content. The All Santa Barbara County option was found to offer the greatest potential for the increased use of greenhouse gas-free electricity with a slight energy bill savings for residential customers, while the City of Santa Barbara Only scenario was the most financially challenging.[3]

### City Council Action - Resolution of Intent

In July 2018, the City Council received a report on the favorable results of the Santa Barbara County study and adopted Resolution No.18-41, a Resolution of Intent authorizing City staff to participate in discussions with the County of Santa Barbara and the Cities of Santa Barbara and Carpinteria in anticipation of the formation of a new Joint Powers Authority (JPA) and CCE program launch. A JPA would administer a new CCE program serving residents, businesses, and governments located within the jurisdictional boundaries of the JPA member agencies.

The adopted resolution did not, however, bind the City to membership in the JPA, allocation of general funds, or participation in a future CCE program. It was anticipated that staff would need to return to Council at a later date to consider: (1) passing a resolution for JPA membership, (2) authorizing a pro-rata share of credit support, and (3) passing a CCE ordinance, as required by Public Utilities Code.

### Update on Efforts Since Council Action

Since the local municipalities opted to discuss formation of a CCE JPA in July 2018, the formation plans for a local program were paused. This was due to several pending policy changes at the State level, including an increased Power Cost Indifference Adjustment (PCIA) or "exit fee,"[4] increased competition from other direct access Energy Service Providers, accelerated State renewable and GHG-free electricity goals, as well as lack of interest by North County jurisdictions to participate in CCE. All of these items raised concerns about the applicability of the previous study results, so PEA was re-engaged to conduct an updated feasibility assessment. The update was to consider these factors as well as adjustments to account for increased wholesale power prices and IOU generation rates for residential customers. The results of the update are discussed in more detail below and included as Attachment 1.

[3] To review the Santa Barbara County CCE Feasibility Study, please visit: http://www.centralcoastpower.org/resources.nrg#fasibility

[4] The PCIA is a charge the incumbent utility imposes on CCA customers for generation commitments made prior to the time the customer takes generation service from the CCA. The PCIA rates are approved by the CPUC.

## DISCUSSION:

### Update to the Santa Barbara County CCE Feasibility Study

For the update to the Santa Barbara County CCE Feasibility Study, PEA evaluated the viability of CCE for the unincorporated areas of Santa Barbara County and the Cities of Goleta, Carpinteria, and Santa Barbara. PEA evaluated total program costs, rate competitiveness, and financial position, assuming the electricity portfolio begins with 50% renewable energy and increases to 60% renewable energy in 2030, as required by the State Renewable Portfolio Standard over an 11-year study period (2021-2031). These findings are predicated on current market and policy conditions and PEA's firsthand knowledge of CCE operations and costs.

PEA concluded that a CCE program for Santa Barbara County appears financially viable with competitively priced electricity rates, sourced from predominantly non-carbon-emitting electric generation sources. Positive operating margins would begin in year three, versus year one in the original study, and are lower than the original study's projections due to various factors. At rate parity with the Investor Owned Utilities, this difference results in below-targeted reserve accumulation for the first four years of program operations, providing less financial security against unexpected expenses and could delay local program development.[5] A cumulative reserve balance equal to 40% of annual operating costs is projected by year 11. Operating margins are projected to increase in 2025, partially due to expected rate increases in PG&E territory due to closure of Diablo Canyon.

Once a sufficient reserve is established, the County and any City partners could choose to use the accumulated revenues to build new local renewable energy projects, offer incentive programs (e.g., energy efficiency, electric vehicles, rooftop solar) or reduce customer electricity rates. A joint powers authority board - if one or more cities join with the County - would decide how to invest this new revenue source.

Start-up costs are estimated at approximately $9 million, which would likely require a guarantee by the members. No voluntary 100% opt-up renewable energy program was modeled, but PEA states in the study that the estimated impact of offering a voluntary opt-up program is de minimis with respect to portfolio planning and program finances.

- **Sensitivity Testing and Alternative Residential-Only Scenario**

Sensitivity analysis was performed to understand the ability of the modeled reserve fund to withstand increases in power prices (50%) and exit fee costs (25%). When compared to accumulated reserve levels, these costs were determined to be fully absorbed in 2021 and 2024, respectively. Additionally, an alternative scenario was developed to examine a CCA program offering service exclusively to residential customers in recognition of the higher per unit margins embedded in current utility rate designs for this customer class. This scenario was found to yield improved financial performance, with positive operating margins beginning in year one, and above-targeted reserve accumulation in nine years

[5] Common practice for operating CCAs in California is to target a minimum annual reserve contribution of 4% of revenues, building toward a reserve balance of at least 40% of annual operating expenses.

of the 11-year study period. Under this scenario, a reserve balance equal to 40% of annual operating costs was projected in year seven. Start-up costs for this scenario are also reduced to $2.5 million.

### City Council Energy & Green Issues Standing Committee

The City Council's Energy / Green Issues Standing Committee received updates on the CCE process twice between July 2018 and June 2019. Staff returned to the Green Committee on July 8, 2019 to provide a briefing on the results of the updated study.

## Joining an Existing CCE Program

### Monterey Bay Community Power

Recently, the County and incorporated cities (including Santa Maria and Guadalupe in North County) were contacted by Monterey Bay Community Power (MBCP) to consider joining its existing CCE program. Begun in early 2018, Monterey Bay Community Power is the first, tri-county community choice energy program that serves the Counties of Santa Cruz, San Benito, and Monterey, as well as 16 incorporated cities therein. Currently, MBCP has about 275,000 customers and will increase to close to 305,000 in early 2020, once the recently joined Cities of Morro Bay and San Luis Obispo are enrolled and begin electric service. Some key components of MBCP are highlighted below and a FAQ document is included in Attachment 3:

- **Financial Health** - MBCP has been able to pay off initial start-up debt and build reserves of approximately $57 million as of February 28, 2019. MBCP estimates reaching its reserve target by late 2020 or early 2021, which would allow greater flexibility on rates and programs. Currently, the MBCP financial policy for net revenues is to allocate 70% towards reserves and 30% for rebates in FY 2018-2019 and once the reserve target is met, 50% of reserves will be put towards energy programs and 50% will be put towards rebates.

- **Rate Structure & Service Offerings** - The basic product provided by MBCP is known as "MBchoice," which is carbon-free, provided at rates that are identical to the rates of the incumbent utility on a monthly basis, and includes a rebate provided as a bill credit. Customers may choose to opt up to "MBprime," which supports 100% California wind and solar. MBprime is set at $0.01/kWh above MBCP default rates. For South County jurisdictions interested in a 100% renewable energy default product, MBCP has indicated that such an offering would be possible and the added cost would also be approximately $0.01/kWh. There are also additional rebate options and an enhanced net energy metering (NEM) rate.

- **Governance and Representation** - Of the 21 jurisdictions in MBCP, the three counties and three jurisdictions with population of 50,000 or greater hold six Board seats. The additional, six Board seats are shared by multiple jurisdictions based on geography. MBCP has a Policy Board, which meets quarterly and is comprised of elected officials, and an Operations Board, which meets eight times per year and is comprised of city managers and county administrative officers. MBCP also has a Community Advisory Council. Members of the Community Advisory Council are community members appointed at large by the Policy Board.

- **Energy Programs and Local Economic Benefits**: MBCP re-invests 2% of revenue into local energy programs focused on transportation electrification, building electrification and distributed energy resources. MBCP currently offers an electric vehicle incentive program as well as a solar effort to support low income customers. To date, MBCP has rebated over $4.4 million dollars to customers in calendar year 2018. MBCP estimates over $8 million in bill savings in CY 2019.
- **Energy Procurement**: MBCP procures carbon-free energy on the wholesale market through a variety of energy suppliers and contract lengths. MBCP's portfolio mix meets the State's renewable portfolio standard, with the remaining sources coming from large hydro-electric suppliers. Recently, MBCP teamed with Silicon Valley Clean Energy[6] to sign contracts for California's largest solar-plus-storage project, as well as a joint-procurement project from a 200-megawatt wind farm, which will come online in 2021 and meet 20% of the current electrical demand. MBCP's energy procurement is supported by its energy risk management policy.
- **Santa Barbara County Presence**: MBCP is committed to unifying the Central Coast under one community choice energy program. To that end, MBCP has expressed a willingness to set up a satellite office to serve Santa Barbara County members and is open to re-branding the agency to a more fitting title, which includes "Central Coast" in it.

A party may withdraw its participation in the CCE program pursuant to terms identified in the JPA. Prior to program launch, a party may withdraw its membership without any financial obligation if, after MBCP receives bids from power suppliers, the bids do not result in 1). Rates equal to or less than SCE, 2). GHG emission rates lower than SCE, or 3). Renewable energy power content higher than SCE. This action requires a 15-day notice to the JPA board and affirmative vote. Following program launch, a minimum six-month notice and affirmative vote of the board is required for withdrawal to take effect at the beginning of the next fiscal year and the party would be liable for applicable costs through the termination date.

### Clean Power Alliance

Begun in 2018, Clean Power Alliance (CPA), is the CCE program serving Los Angeles and Ventura Counties and 29 incorporated cities in southern California, with one more city joining in 2020. Given MBCP's expressed interest in Santa Barbara County jurisdictions joining their program, staff from the south coast jurisdictions contacted CPA staff to better understand their program and potential for joining. CPA is not expanding in 2019, so the earliest possible opportunity to join would be 2020 with customer enrollment

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[6] Silicon Valley Clean Energy is a CCE program serving the jurisdictions of Campbell, Cupertino, Gilroy, Los Altos, Los Altos Hills, Los Gatos, Milpitas, Monte Sereno, Morgan Hill, Mountain View, Saratoga, Sunnyvale and unincorporated parts of Santa Clara County.

starting in 2022 based on CPUC requirements. Looking forward, CPA will likely only accept jurisdictions that will join at a 100% renewable default rate option. Given this information on timing, further details on CPA's program are not included here pending Council direction regarding interest in joining CPA. However, a comparative matrix of CCE program options is included in Attachment 2 including the formation of a new regional program, joining an existing program, or taking no further action.

## Considerations for Moving Forward with Community Choice Energy

### Actions by Adjacent Jurisdictions

To a certain extent, the City's available options for moving forward with a CCE program are linked to actions by neighboring jurisdictions. The following is a summary of the related activities for the Cities of Carpinteria and Santa Barbara, and the County of Santa Barbara.

- **The City of Carpinteria** is taking an informational item to their City Council on July 8, 2019 with the results of the PEA updated study. It is expected that the City of Carpinteria will await further action by other jurisdictions, notably the County of Santa Barbara and City of Santa Barbara, prior to taking further action.

- **The City of Santa Barbara** has engaged PEA in additional analysis of a City of Santa Barbara-only scenario and is evaluating other options for creating its own CCE program, as well as considering options for joining an existing program. Staff is reviewing these options first via the Santa Barbara City Council CCE Subcommittee meetings as recently as June 24, 2019, with additional meetings currently scheduled for July 3, July 17, and July 24. Results of the July 3 Subcommittee meeting will be available for the City of Goleta's Council meeting on July 16.

- **The County of Santa Barbara** will present the results from PEA's study to the Board of Supervisors on July 16, 2019, and is also expected to request direction on pursuing CCE program options, including continuing to form a regional CCE or joining MBCP. Results of that meeting will be available for the City of Goleta's Council meeting later that evening.

### Relationship to Council's 100% Renewable Electricity Goal

The recently released Strategic Energy Plan (SEP) was developed as a roadmap to identify how the City could reach its adopted 100% Renewable Electricity goal by 2030. The SEP identifies strategies in five program areas for the City to prioritize in order to meet its goal. Not surprisingly, CCE contributes significantly to the goal, at approximately 64% of the combined strategies contribution (or approximately 30% overall), as a CCE allows the community to determine what type of energy mix serves its needs, in addition to facilitating other strategies based on CCE operational benefits.

### Options Analysis

Ultimately, there will be a decision point for the County and South Coast jurisdictions whether to proceed with forming a new regional CCE, joining another existing CCE, forming their own individual CCEs, or discontinuing CCE investigation and formation. To assist in comparing these options, Attachment 2 includes a CCE Program Comparative Matrix.

It should be noted that the California energy system is at a critical inflection point, with increasing price volatility driven by increased integration of distributed renewable energy resources on the grid, a changing electricity provider landscape as more CCE programs form, and significant policy uncertainty with ongoing action by the California Public Utilities Commission (CPUC) and State Legislature seeking to enact changes that could affect CCE program viability. These are risks, in addition to the many benefits of CCE programs, that the Council will need to consider.

## Next Steps

### Santa Barbara County CCE Program

Should the City Council elect to continue to move forward with a regional CCE program, the earliest that a new, multi-jurisdiction, JPA-run CCE program could launch is anticipated to be January 2022, due to CPUC requirements, and the time required to negotiate a JPA agreement and operating guidelines among multiple parties. To launch on this date, the CPUC requires an implementation plan be filed by January 1, 2021. The County would likely remain the lead agency and provide staffing and services (e.g., human resources, information technology, procurement) until a JPA can staff up and operate on its own. As indicated previously, staff would need to return to Council at a later date to consider: (1) passing a resolution for JPA membership, (2) authorizing a pro-rata share of credit support, and (3) passing a CCE ordinance.

### Monterey Bay Community Power

Should the Council be interested in joining MBCP and have it serve customers beginning in 2021, rather than pursuing a Santa Barbara County CCE program, the following steps would need to be accomplished:

1. The City Council would need to (1) adopt a CCE ordinance authorizing the implementation of a community choice aggregation program by participating in Monterey Bay Community Power Authority's community choice aggregation program and (2) adopt a resolution joining MBCP and authorizing execution of its JPA Agreement.

2. The City Council would need to do a second reading of the ordinance.

These documents would be brought back for Council consideration and first reading at the meeting of August 20, 2019. This tight turn-around time is necessary because MBCP would need to update its implementation plan and JPA agreement by the end of this year in order to be able to enroll customers and start service in 2021. The end of year deadline is related to CPUC rules that require an implementation plan be filed by a CCE one year prior to serving customers. Action in August would allow MBCP to notify its Board and get authorization prior to filing with the CPUC by the end of the year. Alternatively, the City could wait, but this would delay enrollment and service to customers by one year.

**GOLETA STRATEGIC PLAN:**

The recommended items in this report relate to the following 2019-2021 Strategic Plan strategies, goals, and objectives:

**Strategic Goal:** Adopt best practices in sustainability
**Objective:**

- Participate in the Central Coast Power consortium of local governments to explore the feasibility of Community Choice Energy

**City-Wide Strategy:** Support Environmental Vitality
**Strategic Goal:** Promote renewable energy, energy conservation and local energy resiliency
**Objectives:**

- Implement the Strategic Energy Plan in furtherance of the City's adopted 100% renewable energy goals
- Encourage energy conservation through enhanced insulation, LED replacement lighting and similar measures, including at City-owned facilities
- Encourage renewable energy generation and use through installation of solar panels, electric vehicle charging stations and similar measures, including at City-owned facilities
- Explore adoption of a "Reach" Building Code
- Continue to work with the Santa Barbara County Climate Collaborative to share resources to address climate change

**FISCAL IMPACTS:**

**Santa Barbara County CCE**

No immediate fiscal impact would result from proceeding with discussions of a county-wide community choice energy program. However, JPA formation and early program development costs are expected to be shared equitably among participating jurisdictions. Once such costs are determined, staff would return to Council with a request to consider funding options and potentially the need for additional appropriations.

PEA’s estimated start-up costs are $9 million for all customer classes, or $2.5 million for residential customers only. Due to early year operating losses, initial financing will likely require a guarantee or other form of credit support by JPA members. The participating jurisdictions would need to negotiate a cost-share arrangement, options for securing the loan for full program launch and power procurement costs, and repayment terms. If a CEE program launches, all funds expended to date are reimbursable through future CCE revenues. Estimated annual revenues range from $1.3 million to $15.1 million. Once a sufficient reserve fund is established, the JPA board could make policy decisions about how to spend this new revenue source.

**Monterey Bay Community Power**

There is no cost to join MBCP. However, the City would need to cover incremental costs associated with updating MBCP's Implementation Plan and JPA agreement, which are required to be filed with the CPUC. MBCP staff estimate that it will require an approximately $5,000-$7,500 contribution from each interested jurisdiction for this effort.

**ALTERNATIVES:**

Council may direct staff to continue with formation of a Santa Barbara County CCE program, join another existing CCE program, such as Monterey Bay Community Power, or discontinue further exploration of CCE at this time. If Council chooses not to proceed, staff will return to Council with a request to repeal the CCE Resolution of Intent adopted in July 2018. If Council is interested in joining MBCP, staff will return with appropriate documents for the August 20, 2019 meeting. Additionally, staff is prepared—with ongoing funding as identified in the Strategic Energy Planning process-to continue efforts to pursue other strategies in support of the City's sustainability goals, including the 100% renewable energy goal.

| **Reviewed By:** | **Legal Review By:** | **Approved By:** |
|---|---|---|
| Kristine Schmidt<br>Deputy City Manager | Michael Jenkins<br>City Attorney | Michelle Greene<br>City Manager |

**ATTACHMENTS:**

1. Pacific Energy Advisors, Inc., Community Choice Aggregation Technical Study Update
2. Community Choice Energy Program Comparative Matrix
3. Monterey Bay Community Power Frequently Asked Questions

## ATTACHMENT 1

## Pacific Energy Advisors, Inc., Community Choice Aggregation Technical Study Update

PEA
Pacific Energy Advisors, Inc.

# Memorandum

To: Ashley Watkins, Division Chief, Sustainability, County of Santa Barbara

From: Pacific Energy Advisors, Inc.

Subject: Community Choice Aggregation Technical Study Update

Date: June 14, 2019

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## Executive Summary

In May 2018, a Community Choice Aggregation (CCA) Technical Study (Study) was prepared for the County of Santa Barbara (SBC or the County), by Pacific Energy Advisors, Inc. (PEA) under contract with SBC, for purposes of determining the potential feasibility of forming a CCA program within all or part of Santa Barbara County.[1] The Study evaluated three membership configurations. Under each membership configuration, three distinct supply scenarios were evaluated, each reflecting varying levels of renewable energy[2] and greenhouse gas (GHG)-free energy[3] supply as well as associated costs.

Several developments have led SBC to request an update to the original Study, addressing revised membership and updates to key market and regulatory assumptions. The updated analysis (Update) examines the feasibility of a CCA program serving the unincorporated areas of the County as well as the Cities of Carpinteria, Goleta, and Santa Barbara. The analysis also reflects revised assumptions related to utility rates and wholesale electricity prices as well as revisions related to the recent California Public Utilities Commission (CPUC) proceeding that reformed the methodology for calculating the Power Charge Indifference Adjustment (PCIA).[4] As instructed, PEA modeled a CCA supply portfolio that would exceed the renewable energy and GHG-free content of the expected electric supply portfolios to be offered by the incumbent investor-owned utilities, Pacific Gas and Electric (PG&E) and Southern California Edison (SCE). The CCA is modeled with an 85% GHG-free supply portfolio, with qualifying renewable energy content starting at 50% and increasing to 60% by 2030, as required by the state Renewables Portfolio Standard (RPS).

The Update assesses the potential CCA over an 11-year study period: 2021-2031. The CCA is assumed to start operations in 2020 in preparation for CCA-sourced electricity to begin flowing to customers in 2021, the earliest year that service could begin in light of CPUC timing requirements.[5]

Based on the analyses conducted during this Update, PEA concludes that SBC could operate a CCA

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[1] The original Study is available at: http://www.centralcoastpower.org/resources.nrg#fasibility.

[2] As defined by the State Renewables Portfolio Standard (RPS).

[3] GHG-free electricity refers to electric energy generated from sources that do not emit (or emit very low amounts of) gases which contribute to the greenhouse effect, such as carbon dioxide, methane, and nitrous oxide. GHG-free power sources typically include RPS-eligible renewable energy and hydroelectric generating resources.

[4] The PCIA is a charge the incumbent utility imposes on CCA customers for generation commitments made prior to the time the customer takes generation service from the CCA. The PCIA rates are approved by the CPUC.

[5] The original study assumed service would commence to customers in 2020.

program providing competitively priced electricity, sourced from predominantly non-carbon emitting electric generation sources. The prospective CCA could set rates equal to PG&E and SCE. However, at rate parity, the CCA would accumulate financial reserves smaller than levels achieved by other CCAs that were formed in the last few years. These comparatively smaller reserves would provide less financial security against unexpected cost shocks. Further, to address early year operating losses, the initial financing for program operations may require a guarantee or other form of credit support provided by the JPA members. Accelerating reserve contributions could build healthier reserves but would require higher rates charged to customers or other funding sources as further discussed below. Alternatively, a program initially targeted to residential customers would be more financially viable, with stronger operating profits, healthier reserve levels, and lower financing requirements.

Ultimately, SBC's ability to demonstrate rate competitiveness (while also offering environmental benefits) would hinge on prevailing market prices at the time of power supply contract negotiation and execution. Depending on inevitable changes to market prices and other assumptions such as IOU generation rates and the PCIA, SBC's actual electric rates may be somewhat lower or higher than similar rates charged by the IOUs and would be expected to fall within a competitive range needed for program viability.

## Introduction

This Update addresses the potential benefits and liabilities associated with forming a County-based CCA program over an eleven-year planning horizon (2021-2031). The CCA is assumed to commence preliminary operational activities in 2020 in preparation for CCA-sourced electricity to begin flowing to customers in 2021, the earliest year that service could begin in light of CPUC timing requirements. The original Study assumed service would begin in 2020.

Projected operating results are dependent upon a variety of factors and assumptions, including but not limited to:

- Recent wholesale energy and capacity product pricing and availability;
- The County's desired electric power portfolio composition, which is expected to include significant use of renewable energy and other GHG-free energy sources;
- Anticipated retail generation rates of SCE and PG&E, the incumbent IOUs within the County;
- Estimated PCIA rates and other surcharges, or exit fees, which are imposed on CCA customers;
- Expected financing and administrative costs of the CCA program;
- Other cost elements at the time of assessment completion; and
- PEA's extensive direct experience with many of California's operational CCA programs.[6]

As requested by SBC, communities to be served by the prospective CCA initiative include the unincorporated areas of Santa Barbara County and the Cities of Carpinteria, Goleta, and Santa Barbara. PEA was tasked with updating the pro forma analysis assuming the electricity portfolio begins with 50% renewable energy and increases to 60% renewable energy in 2030, as required by the State RPS. Using this baseline, PEA examined general rate competitiveness and financial viability of a CCA program serving the jurisdictions listed above in light of recent market and policy changes.

[6] PEA has unique experience with California CCA program evaluation, development and operation, having provided broad functional support to many operational California CCAs, including Marin Clean Energy, Sonoma Clean Power, Lancaster Choice Energy, CleanPowerSF, Peninsula Clean Energy, Silicon Valley Clean Energy, Pioneer Community Energy, Monterey Bay Community Power and several others.

## Regulatory Environment

Rapid acceleration of CCA throughout the state has heightened regulatory and legislative focus on these relatively new entities, resulting in a general increase in regulation of CCAs. Recently, the CPUC has taken an expansive view of its regulatory authority over CCA resource planning. Despite CCA objections regarding the CPUC's legal authority to regulate CCA procurement, the CPUC appears intent on extending certain elements of the regulatory framework, which have been historically applied to investor-owned utility resource planning, to CCA organizations as well. Up to this point, increases in CPUC-administered regulatory requirements have taken the form of expanded reporting obligations, which generally increase costs associated with regulatory compliance while disproportionately impacting small CCA programs. Of greater concern is the CPUC's apparent inclination to exert increased control over CCA resource procurement decisions in such forums as the Integrated Resource Planning proceeding and the Resource Adequacy proceeding. Additionally, policymakers have made proposals and proposed legislation to establish a "central buyer" with responsibility for procurement of certain "preferred" resources, with such costs spread to all load serving entities. If unchecked, these trends threaten CCA resource planning and procurement autonomy. With the growing political power of CCAs, evolution of the regulatory environment will likely balance CCA interests with the State's interest in maintaining control over the electric system. In the meantime, the regulatory environment remains highly fluid and will undoubtedly undergo significant change over the next several years; by forming a CCA, SBC should be prepared for active participation in shaping statewide and local energy policy in order to maintain long-term operational viability.

Another recent regulatory development includes the limited re-opening of direct access, which allows bundled customers the ability to receive generation service from private energy services companies, beginning in 2021. Statewide, a total of 4,000 GWh (annual energy sales) allowed for new direct access transactions will be apportioned among the respective investor-owned utility service territories. The expansion represents an approximately 15% increase in direct access eligible load. PEA does not anticipate material changes to the SBC CCA pro forma resulting from this expansion of direct access.

The RPS requirements that would be applicable to an SBC CCA have increased as a result of the enactment of Senate Bill 100, increasing to 60% by 2030 from the previous 50% requirement. The new RPS requirements have been reflected in this update. Further, the SBC CCA will need to demonstrate it has long-term (10 years or longer) contracts for at least 65% of its renewable portfolio requirements for the compliance period commencing on January 1st, 2021 as well as each compliance period thereafter. The long-term contracting requirement may be challenging for a newly operating CCA because the CCA's credit profile tends to build over time, and long-term contracts pose significant credit exposure to the sellers. Security arrangements such as a "lockbox" or alternative credit support structure for securing buyer obligations under the long-term contract(s) would need to be explored during the implementation phase.

## SBC's Prospective Customers

Currently, electric customers within SBC are served by either SCE or PG&E, depending on the geographic area in which such customers reside. Collectively, the IOUs serve approximately 112,400 combined electric accounts (85,400 by SCE, and 27,000 by PG&E) within the member communities of Santa Barbara

County, representing a mix of residential (≈84%), commercial (≈14%) and agricultural (≈2%) accounts.[7] These customers consume nearly 2.1 billion kilowatt-hours ("kWh") of electric energy each year.[8] While the majority of customers fall under the residential classification, such accounts historically consume only 26% of the total electricity delivered by the IOUs. The balance of SBC's historical electricity sales (≈74% of the total) are substantially related to commercial (≈29%), industrial (≈35%) and agricultural (≈10%) usage. The current utility rate structures generally charge the lowest rates to large commercial, industrial, and agricultural customers, and the prevalence of these customers in SBC results in lower overall margins available to the CCA program.

Under CCA service, each of these accounts could be enrolled in the SBC program; the precise timing of customer enrollment, and any related phasing decisions of the CCA program, if any, would be determined during the implementation period. For purposes of this Update, it was assumed that all customers would be enrolled during the month of January 2021, which is the earliest time that a CCA program could launch under current State regulations.[9]

Consistent with California law, customers may elect to take service from the CCA provider or remain with SCE or PG&E, a process known as "opting-out." For purposes of the Update, PEA utilized current participatory statistics compiled by California's operational CCA programs to derive an assumed participation rate of 90% for the SBC program; the remaining 10% of regional customers (not including Direct Access customers, which would not be enrolled by the CCA program for purposes of avoiding duplicative customer charges and/or contractual issues for such accounts) are assumed to opt-out of the SBC program and would continue receiving generation service from the IOUs. Customer account and energy usage projections referenced throughout this Update reflect such adjustment.

## SBC's Indicative Supply Portfolio

For purposes of the Update, PEA modeled a supply portfolio that would improve upon the status quo for use of renewable energy, relative to assumed portfolio compositions of the incumbent IOUs, as well as related metrics for GHG emissions intensity. The SBC supply portfolio is initially comprised of 50% qualifying renewable energy, increasing to 60% by 2030, in accordance with the requirements of SB100.[10]

Overall GHG-free content for the prospective CCA program is held steady at an average of 85% throughout the study period. As indicated in the original Study, PG&E is expected to maintain a substantially GHG-free resource mix, approaching 100% in the near term, at least until retirement of the Diablo Canyon nuclear power plant occurs in 2024-2025. With this in mind, the prospective CCA supply portfolio assumes 100% GHG-free energy for load served in the PG&E service area and 75% GHG-free energy for load served in the SCE service area, resulting in an overall GHG-free content of 85% for the CCA's composite supply

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[7] Prospective account totals reflect only bundled customers served exclusively by the applicable IOU and exclude Direct Access customers who procure their electricity supply from a provider other than PG&E or SCE. Of note, the University of California, Santa Barbara is included as a bundled SCE customer. However, staff has indicated that the university is expected to become a Direct Access customer and therefore will likely not be served by the CCA.

[8] Reflects bundled customer electricity usage in calendar year 2015.

[9] This timing assumes participating member agencies form a JPA and submit a CCA Implementation Plan & Statement of Intent to the CPUC before January 1, 2020.

[10] Consistent with California's RPS laws, retail sellers of electric energy, including CCAs, must procure a minimum 33% of all electricity from eligible renewable energy sources by 2020; with the recent enrollment of Senate Bill 100, California's RPS procurement mandate has been increased to 60% by 2030.

portfolio.

The various energy supply components of the modeled supply portfolio are broadly categorized as:

- Conventional Supply (generally, electric energy produced through the combustion of fossil fuels, particularly natural gas within the California energy market);
- "Portfolio Content Category 1 (PCC1)" or "Bucket 1" Renewable Energy Supply (generally renewable energy produced by generating resources located within or delivering power directly to California);
- "Portfolio Content Category 2 (PCC2)" or "Bucket 2" Renewable Energy Supply (generally renewable generation produced outside of California with associated energy import requirements);
- "Portfolio Content Category 3 (PCC3)" or "Bucket 3" Renewable Energy Supply (environmental attributes of metered renewable energy production, conferred in the form of a renewable energy certificate (REC), which is sold separately from the electric power; Bucket 3 renewable energy is commonly produced outside of California and is colloquially referred to as an "unbundled REC"); and
- Additional GHG-Free Supply (generally power produced by regionally located hydroelectric generating facilities, which do not meet the eligibility requirements of California's RPS program – such requirements render larger hydroelectric generators in excess of 30 MW ineligible to participate in California's RPS program).

As in the original Study, the renewable energy to be procured by the CCA is predominantly assumed to be from sources and contracts meeting the definition/delivery requirements of PCC1, which are typically located within California. The volumes of renewable energy modeled as PCC2 and PCC3, which are supplied from out of state renewable generators, were limited to 15% and 10% of applicable Renewables Portfolio Standard requirements, respectively. This translates to an overall portfolio content of 5.4% PCC2 and 3.6% PCC3 in year 1 (2021) and 9.0% PCC2 and 6.0% PCC3 in year 11 (2031). All PCC2 and PCC3 volumes are matched by additional purchases of other GHG-free (large hydro) energy to ensure that targeted GHG-free targets are met. [11] PEA encourages the County to actively monitor implementation activities associated with AB 1110 to ensure that any eventual procurement decisions made by the CCA program appropriately consider the final methodological guidelines adopted by the California Energy Commission (for power source reporting and related portfolio emissions calculations), which may somewhat differ from those assumptions reflected in this Update.

[11] Industry accepted GHG accounting practices generally recognize eligible renewable energy sources as GHG-free. However, California's ongoing implementation of Assembly Bill 1110 (Ting, 2016) will alter such practices, imposing a new retail-level GHG emissions calculation methodology that may eliminate the emissions benefits historically attributed to certain renewable energy products. In particular, the California Energy Commission's staff proposal regarding AB 1110 implementation suggests that many Bucket 2 renewable energy products and all Bucket 3 products would be ascribed a non-zero GHG emissions rate generally equivalent to system-wide purchases. Specific details regarding AB 1110 implementation remain under development and will not be finalized until later in 2019. Note that AB 1110 will be effective for all power purchases occurring on and after January 1, 2019. Also, under all supply scenarios, incremental purchases of non-RPS-eligible GHG-free sources, specifically electricity produced by larger hydroelectric resources (with nameplate generating capacity in excess of 30 megawatts) would be procured by SBC to achieve targeted GHG emissions reductions.

*Figure 1: Indicative Supply Portfolio Composition PG&E Territory*

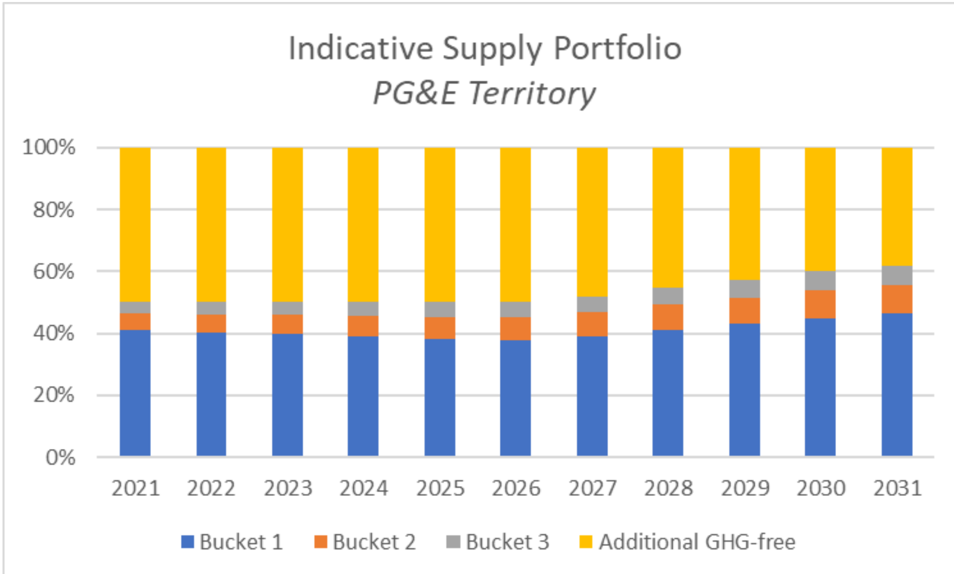
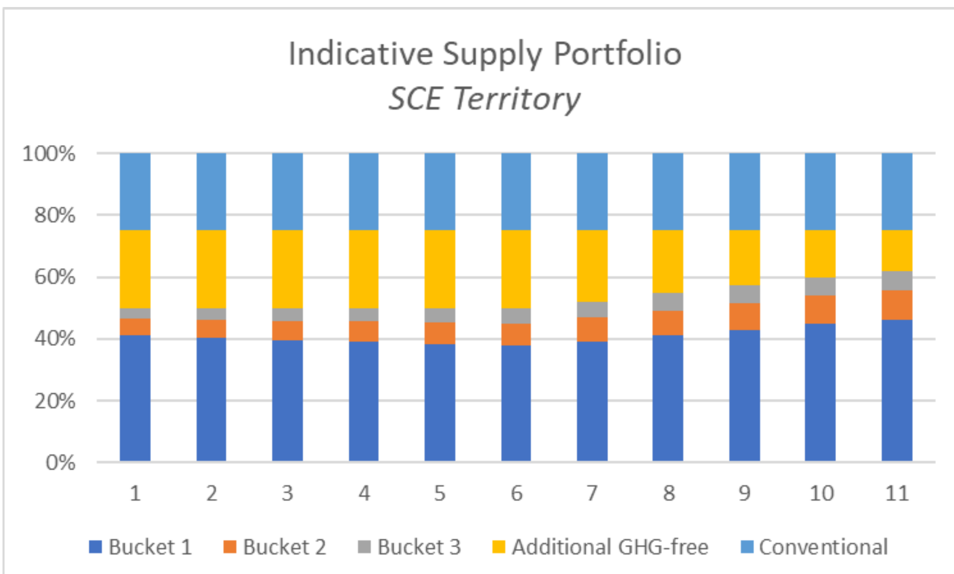



*Figure 2: Indicative Supply Portfolio SCE Territory*




It should be noted that SBC would not be limited to the particular portfolio assessed in this Update. The studied portfolio serves to demonstrate the potential operating outcomes of a new CCA program that would offer a cleaner supply portfolio than the incumbent utilities, while balancing ratepayer costs. Prior to the procurement of any particular energy product(s), SBC would have an opportunity to refine its desired resource mix, which may differ from the portfolio choices reflected herein.

**General Operating Projections**

The pro forma financial projections contained in Exhibit 2 indicate the expected revenues and costs associated with CCA program operation, assuming that CCA generation rates are set at parity with projected rates of the incumbent utilities. Positive operating margins are projected to begin in the third year of program operations, and achievement of a targeted reserve balance equal to 40% of annual operating expenses is projected to occur in Year 11 (2031). Reserve levels average around $7 million during the first four years of CCA program operation, before beginning a growth trajectory during which reserves grow to approximately $77 million by 2031. The expected increase in reserve levels is partly the result of anticipated increases in PG&E generation rates around 2025, the time when decommissioning of PG&E's Diablo Canyon nuclear power plant is expected to occur.[12]

In Exhibit 2, the projected "Actual Reserve Contribution" during each year of the study period reflects the projected net revenues (or deficits) that would be realized by the SBC CCA if the program decided to offer customer electric rates that were equivalent to similar rates charged by the IOUs. To the extent that the Actual Reserve Contribution is equal to or greater than the targeted reserve contribution, SBC would have the potential to offer comparatively lower customer rates/charges, relative to similar rates imposed by the IOUs; to the extent that the Actual Reserve Contribution is less than the targeted reserve contributions, SBC would need to impose comparatively higher generation rates to recover expected costs, or operate with a lower than desired operating reserve. The Actual Reserve Contribution is higher than the 4% of annual revenues target in 7 years and lower than the target contribution in 4 years.

The initial results for the combined-IOU pro forma indicate positive operating margins beginning in year 3 (2023) and below targeted reserve accumulation for the first four years of program operations. Consequently, during this period there would be relatively few financial reserves available to ensure rate stability by absorbing fluctuations in revenues or power costs. Operating margins are projected to strengthen in 2025, due in part to expected rate increases associated with closure of Diablo Canyon, and PG&E's need to replace this energy at prevailing market prices. A cumulative reserve balance equal to 40% of annual operating costs is projected by year 11 (2031).

If CCA rates were set independently of the incumbent utilities' rates, and instead were designed to fully recover costs and contribute 4% of annual revenues to reserves (the reserve contribution level used in the original Study and common among CCAs), such CCA rates are projected to be 3% higher on average than the incumbent utilities' generation rates for the first four years of CCA program operations, before falling to rate parity (or below) thereafter.[13] It should be noted that a 3% generation cost premium would translate to an overall bill impact (including generation and delivery charges) of approximately 1.5%, a level which PEA considers competitive and not likely to materially impact customer participation. Rates can be competitive without necessarily being lower as the CCA could provide numerous benefits to the community in the form of reduced GHG emissions, innovative local programs, and local control over key energy policies. These benefits may be worthy of community investment, either in the form of temporarily higher rates or through direct member funding to augment the program's initial reserves.

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[12] As indicated in PG&E's 2018 Integrated Resource Plan (https://www.pge.com/en_US/for-our-business-partners/energy-supply/integrated-resource-plan/integrated-resource-plan.page?WT.mc_id=Vanity_irp).

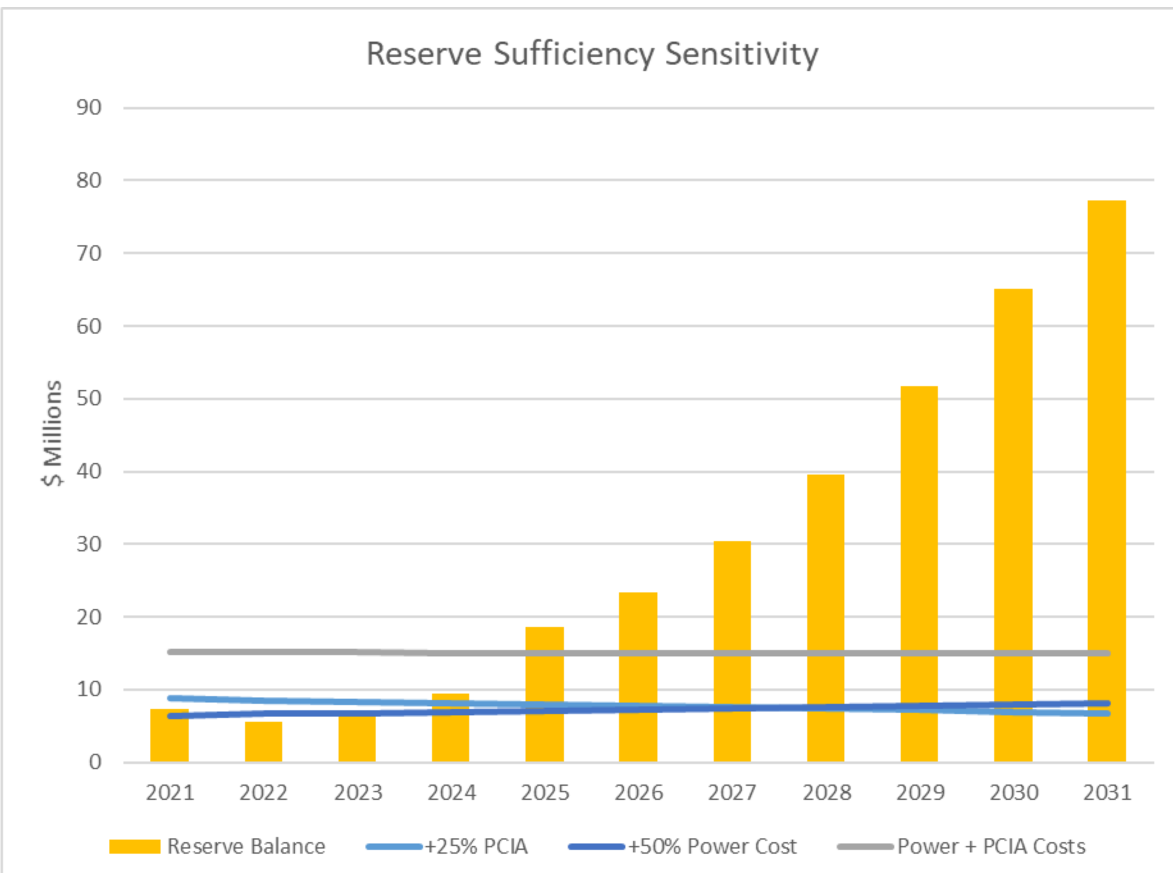
[13] The rate premium is assumed to apply on a uniform percentage basis to all customers served by the SBC CCA. Actual rate design would be under the discretion of the SBC CCA Governing Board.

## Sensitivity Analysis

In response to SBC's request to better understand the ability of the modeled reserve fund to weather adverse changes in power prices and PCIA costs, PEA performed sensitivity analyses involving the variability of those costs. The increased cost was evaluated by year relative to accumulated reserves. Baseline PCIA projections comprise approximately 20% of the CCA customer's generation costs. To represent a reasonable range of outcomes, PCIA costs were increased by 25% relative to the baseline projections. Power costs were stressed assuming a 50% increase in costs associated with the CCA program's annual open position, which is expected to be approximately 10% of total energy requirements during each year of program operation.[14]

When compared to Accumulated Reserve Levels, a 50% increase in spot market power costs could be fully absorbed as early as 2021, and a 25% increase in PCIA could be absorbed by 2024. In the unlikely event that both contingencies were to occur at the same time, the accumulated reserve balance would be sufficient to cover the combined cost increase beginning in 2025. Further details can be seen in Figure 3.

*Figure 3: Reserve Sufficiency Sensitivity*




[14] Assumes minimum of 90% fixed priced coverage for all power supply costs in any given year. Volatility on power prices was derived using historical prices over the past 10 years, which captures the market movements during the natural gas boom/bust and the Great Recession. In order to capture extreme movements, the prices were stressed using a 95% confidence interval. The PCIA sensitivity is similarly expected to capture a range of reasonably likely outcomes for that cost variable.

| Reserve Summary | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
| Reserve Balance | 7 | 6 | 7 | 9 | 19 | 23 | 30 | 40 | 52 | 65 | 77 |
| | | | | | | | | | | | |
| +50% Power Cost | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 |
| +25% PCIA | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 |
| Power + PCIA Costs | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |

## Alternate Customer Mix Sensitivity

An alternative scenario was developed to examine the viability of the SBC CCA program offering service exclusively to residential customers in recognition of the higher per unit margins embedded in current utility rate designs for this customer class. This scenario utilizes the same supply portfolio parameters and assumes service is offered to all residential customers at generation rates equivalent to those charged by the incumbent utilities. Per law, the SBC CCA program would be obligated to offer service to all residential customers, but no such service obligation extends to other customer classes. Staffing and certain other administrative costs were reduced in this scenario, consistent with the narrower customer segment served by the CCA. Financing requirements were also reduced due to lower startup costs and positive cash flows.

Focusing the program on residential customers is projected to yield improved financial performance. The pro forma projections indicate positive operating margins beginning in year 1 (2021) and above targeted reserve accumulation in 9 of the 11 years in the study period. A cumulative reserve balance equal to 40% of annual operating costs is projected to be achieved in year 7 (2027).

## Findings and Conclusions

Based on the updated analyses, PEA finds that a prospective CCA program for Santa Barbara County appears financially viable, and that competitive rates could be offered, while supplying a highly renewable and largely GHG-free energy mix. Projected operating margins are lower than the original Study's projections due to the revised membership configuration with lower CCA load in the PG&E service area, the CPUC's recent revisions to the PCIA methodology, and generally higher wholesale energy costs prevailing since the time of the original Study. Consequently, projected reserve contributions under an 85% GHG-free supply scenario, with rates set to achieve parity with the incumbent utilities, are below industry norms.[15] This could be addressed by charging higher rates; by the member municipalities contributing additional funding to seed program reserves; or by targeting program eligibility to residential (and possibly small commercial customers) until such time as it becomes economic to serve the larger commercial and industrial customer base.

Ultimately, SBC's rate competitiveness (while also offering environmental benefits) would hinge on prevailing market prices at the time of power supply contract negotiation and execution. Depending on inevitable changes to market prices and other assumptions, such as IOU generation rates and exit fees (i.e., the PCIA), SBC's actual electric rates may be somewhat lower or higher than similar rates charged by the IOUs and would be expected to fall within a competitive range needed for program viability.

[15] Common practice for operating CCAs in California is to target a minimum annual reserve contribution of 4% of revenues, building toward a reserve balance of at least 40% of annual operating expenses. Some CCAs, particularly those operating in the PG&E service area, have been able to achieve much higher reserve contributions in recent years, due to relatively high utility rates and low wholesale market prices. Going forward, PEA expects reduced operating margins across the industry.

## EXHIBIT 1 – KEY ASSUMPTIONS

### Generally

*Unless otherwise noted, all assumptions are the same as the original Study delivered in 2018.*

- Customer opt-out rate of 10% for all scenarios.
- Start-up costs of approximately $9 million (consisting predominantly of 72% working capital, and 28% startup costs), funded by a 3% interest revolving credit line, assumed to be retired after ten years. It is likely that the startup portion would require a guarantee by the members and possible that the working capital portion would as well. In the residential-only sensitivity scenario, total financing is reduced to $2.5 million and retired after eight years.
- Targeted annual reserve contributions fixed at 4% of annual revenue. Cumulative reserve target fixed at 40% of annual operation expenses.
- Based on published market prices and recent transactions for similar energy products, average energy costs were modeled as follows:

| PG&E ($/MWh) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| Shaped Energy | $ 45.23 | $ 45.97 | $ 46.40 | $ 47.07 | $ 47.97 | $ 48.96 | $ 49.45 | $ 49.95 | $ 50.45 | $ 50.95 |
| Bucket 1 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 |
| Bucket 2 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 |
| Bucket 3 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 |
| System RA ($/KW-Mo) | $ 4.95 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 |
| Bay Area RA ($/KW-Mo) | $ 5.32 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 |
| Other PG&E RA ($/KW-Mo) | $ 5.32 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 |
| Carbon Free Premium | $ 3.18 | $ 3.28 | $ 3.38 | $ 3.48 | $ 3.58 | $ 3.69 | $ 3.80 | $ 3.91 | $ 4.03 | $ 4.15 |

| SCE ($/MWh) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| Shaped Energy | $ 42.55 | $ 43.41 | $ 44.03 | $ 44.77 | $ 45.73 | $ 46.75 | $ 47.22 | $ 47.69 | $ 48.17 | $ 48.65 |
| Bucket 1 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 | $ 17.00 |
| Bucket 2 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 | $ 6.50 |
| Bucket 3 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 | $ 2.00 |
| System RA ($/KW-Mo) | $ 4.95 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 | $ 5.45 |
| LA Basin ($/KW-Mo) | $ 5.32 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 |
| BC/Ventura ($/KW-Mo) | $ 5.32 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 | $ 5.85 |
| Carbon Free Premium | $ 3.18 | $ 3.28 | $ 3.38 | $ 3.48 | $ 3.58 | $ 3.69 | $ 3.80 | $ 3.91 | $ 4.03 | $ 4.15 |

- No utility-scale local generation supply sources were assumed within Santa Barbara County. Bucket 1/PCC1 supply is generally from in-state renewable resources, Buckets 2 and 3 are from out-of-state sources, and additional GHG-free supply is assumed to come from large hydroelectric generators located in California and throughout the Pacific Northwest.
- Approximately 15% of SBC's retail load would be from unspecified system energy and purchases from the CAISO market.
- The required CCA bond is assumed at $147,000, consistent with current requirements.
- Annual staffing costs were derived by benchmarking to currently operating CCAs of similar size; estimated at $3,000,000, with corresponding staffing levels of approximately 17 full time equivalents. In the residential-only sensitivity scenario, staffing costs are estimated at $1,800,000, with corresponding staffing levels of approximately 10 full time equivalents.
- All scenarios consider a single phase of customer enrollments.
- Uncollectable debts are assumed at 0.5% of revenue, consistent with current bad debt levels seen by other CCAs.

- No voluntary 100% opt-up renewable energy program was modeled; the estimated impact of offering a voluntary opt-up program is de minimus with respect to portfolio planning and program finances.
- The impact of Distributed Energy Resources on CCA load is considered to the extent that it will be offset by growth in other areas such as the increase in demand from electric vehicles.

**<u>SCE Inputs</u>**

<u>Annual Rate Growth</u>[16]

- Generation rates (net of CRS):

| SCE Generation<br>Annual Average Rates ($/MWh) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| D | $ 81.73 | $ 84.12 | $ 86.54 | $ 88.99 | $ 91.46 | $ 93.96 | $ 96.49 | $ 99.06 | $ 101.65 | $ 104.28 |
| GS-1 | $ 77.50 | $ 79.64 | $ 81.80 | $ 83.99 | $ 86.20 | $ 88.45 | $ 90.72 | $ 93.02 | $ 95.35 | $ 97.72 |
| TC-1 | $ 61.62 | $ 63.39 | $ 65.18 | $ 66.98 | $ 68.81 | $ 70.66 | $ 72.54 | $ 74.44 | $ 76.36 | $ 78.31 |
| GS-2 | $ 65.29 | $ 67.19 | $ 69.11 | $ 71.05 | $ 73.02 | $ 75.00 | $ 77.02 | $ 79.05 | $ 81.12 | $ 83.21 |
| TOU-GS | $ 60.81 | $ 62.59 | $ 64.39 | $ 66.21 | $ 68.05 | $ 69.91 | $ 71.80 | $ 73.70 | $ 75.63 | $ 77.59 |
| TOU-8-Sec | $ 57.25 | $ 58.95 | $ 60.67 | $ 62.40 | $ 64.15 | $ 65.93 | $ 67.72 | $ 69.54 | $ 71.37 | $ 73.23 |
| TOU-8-Pri | $ 56.01 | $ 57.67 | $ 59.35 | $ 61.04 | $ 62.76 | $ 64.49 | $ 66.24 | $ 68.02 | $ 69.81 | $ 71.63 |
| TOU-8-Sub | $ 50.07 | $ 51.58 | $ 53.11 | $ 54.65 | $ 56.20 | $ 57.78 | $ 59.37 | $ 60.98 | $ 62.61 | $ 64.26 |
| TOU-PA-2 | $ 54.47 | $ 56.11 | $ 57.77 | $ 59.45 | $ 61.14 | $ 62.85 | $ 64.59 | $ 66.34 | $ 68.11 | $ 69.91 |
| TOU-PA-3 | $ 48.83 | $ 50.34 | $ 51.87 | $ 53.41 | $ 54.96 | $ 56.53 | $ 58.12 | $ 59.73 | $ 61.36 | $ 63.00 |
| Street Lights | $ 37.66 | $ 38.92 | $ 40.19 | $ 41.47 | $ 42.76 | $ 44.06 | $ 45.38 | $ 46.71 | $ 48.05 | $ 49.41 |

- Exit fees (Cost Responsibility Surcharge):

| Cost Responsibility Surcharge<br>SCE Average Rates ($/MWh) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| D | $ 16.09 | $ 15.65 | $ 15.22 | $ 14.81 | $ 14.42 | $ 14.03 | $ 13.66 | $ 13.30 | $ 12.95 | $ 12.61 |
| GS-1 | $ 12.55 | $ 12.21 | $ 11.89 | $ 11.57 | $ 11.27 | $ 10.97 | $ 10.69 | $ 10.41 | $ 10.15 | $ 9.89 |
| TC-1 | $ 11.39 | $ 11.08 | $ 10.78 | $ 10.50 | $ 10.22 | $ 9.94 | $ 9.68 | $ 9.43 | $ 9.18 | $ 8.95 |
| GS-2 | $ 12.63 | $ 12.28 | $ 11.95 | $ 11.63 | $ 11.32 | $ 11.02 | $ 10.72 | $ 10.44 | $ 10.17 | $ 9.91 |
| TOU-GS | $ 11.98 | $ 11.65 | $ 11.34 | $ 11.03 | $ 10.74 | $ 10.45 | $ 10.17 | $ 9.90 | $ 9.64 | $ 9.39 |
| TOU-8-Sec | $ 11.68 | $ 11.37 | $ 11.06 | $ 10.76 | $ 10.47 | $ 10.19 | $ 9.92 | $ 9.65 | $ 9.40 | $ 9.15 |
| TOU-8-Pri | $ 11.39 | $ 11.08 | $ 10.78 | $ 10.49 | $ 10.20 | $ 9.93 | $ 9.67 | $ 9.41 | $ 9.16 | $ 8.93 |
| TOU-8-Sub | $ 10.71 | $ 10.42 | $ 10.13 | $ 9.86 | $ 9.59 | $ 9.33 | $ 9.08 | $ 8.84 | $ 8.61 | $ 8.38 |
| TOU-PA-2 | $ 11.68 | $ 11.36 | $ 11.05 | $ 10.75 | $ 10.46 | $ 10.18 | $ 9.90 | $ 9.64 | $ 9.39 | $ 9.14 |
| TOU-PA-3 | $ 11.22 | $ 10.91 | $ 10.62 | $ 10.32 | $ 10.04 | $ 9.77 | $ 9.51 | $ 9.25 | $ 9.01 | $ 8.77 |
| Street Lights | $ 10.56 | $ 10.26 | $ 9.98 | $ 9.70 | $ 9.43 | $ 9.17 | $ 8.92 | $ 8.68 | $ 8.44 | $ 8.22 |

- Annual load growth is assumed at 0.5%

<u>CAISO costs</u>

- CAISO cost: $1.60/MWh
- Distribution losses: 6%
- Scheduling fees:  $0.40/MWh

<u>Other costs</u>

- Data Manager Charges of $1.15 per account per month
- Utility Service Fees of $1.25 per account per month

**PG&E Inputs**

Annual Rate Growth

- Generation rates (net of PCIA/FFS):

| PG&E Generation<br>Annual Average Rates ($/MWh) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| E-1 | $ 87.93 | $ 88.50 | $ 92.17 | $ 95.23 | $ 105.32 | $ 100.23 | $ 103.68 | $ 107.57 | $ 112.36 | $ 118.52 |
| E-7 | $ 87.79 | $ 88.36 | $ 92.03 | $ 95.09 | $ 105.17 | $ 100.09 | $ 103.53 | $ 107.42 | $ 112.21 | $ 118.36 |
| A-1 | $ 85.94 | $ 86.50 | $ 90.09 | $ 93.08 | $ 102.96 | $ 97.98 | $ 101.35 | $ 105.16 | $ 109.84 | $ 115.87 |
| A-6 | $ 102.75 | $ 103.25 | $ 107.24 | $ 110.54 | $ 121.73 | $ 115.91 | $ 119.66 | $ 123.91 | $ 129.17 | $ 135.96 |
| A-10 | $ 87.66 | $ 88.25 | $ 91.95 | $ 95.04 | $ 105.20 | $ 100.10 | $ 103.58 | $ 107.50 | $ 112.32 | $ 118.52 |
| E-19-S | $ 81.39 | $ 81.93 | $ 85.35 | $ 88.21 | $ 97.61 | $ 92.89 | $ 96.10 | $ 99.73 | $ 104.19 | $ 109.93 |
| E-19-P | $ 73.27 | $ 73.84 | $ 77.07 | $ 79.77 | $ 88.54 | $ 84.22 | $ 87.25 | $ 90.66 | $ 94.85 | $ 100.21 |
| E-19-T | $ 57.39 | $ 58.00 | $ 60.86 | $ 63.27 | $ 70.80 | $ 67.27 | $ 69.95 | $ 72.94 | $ 76.58 | $ 81.22 |
| E-20-S | $ 76.44 | $ 76.96 | $ 80.19 | $ 82.89 | $ 91.76 | $ 87.32 | $ 90.36 | $ 93.78 | $ 98.00 | $ 103.41 |
| E-20-P | $ 76.33 | $ 76.81 | $ 79.97 | $ 82.61 | $ 91.34 | $ 86.93 | $ 89.90 | $ 93.26 | $ 97.40 | $ 102.71 |
| E-20-T | $ 68.57 | $ 69.04 | $ 71.93 | $ 74.35 | $ 82.28 | $ 78.30 | $ 81.02 | $ 84.09 | $ 87.86 | $ 92.70 |
| TC-1 | $ 75.63 | $ 76.22 | $ 79.57 | $ 82.37 | $ 91.44 | $ 86.97 | $ 90.11 | $ 93.65 | $ 97.98 | $ 103.53 |
| Ag | $ 79.61 | $ 80.09 | $ 83.35 | $ 86.07 | $ 95.09 | $ 90.51 | $ 93.57 | $ 97.04 | $ 101.31 | $ 106.80 |
| Street Lights | $ 70.02 | $ 70.48 | $ 73.41 | $ 75.86 | $ 83.93 | $ 79.87 | $ 82.63 | $ 85.74 | $ 89.57 | $ 94.49 |

- Exit fees (PCIA and franchise fees surcharge):

| PCIA and Franchise Fee Surcharge<br>PG&E Average Rates ($/MWh) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| E-1 | $ 30.58 | $ 29.66 | $ 28.77 | $ 27.91 | $ 27.07 | $ 26.26 | $ 25.47 | $ 24.71 | $ 23.97 | $ 23.25 |
| E-7 | $ 30.58 | $ 29.66 | $ 28.77 | $ 27.91 | $ 27.07 | $ 26.26 | $ 25.47 | $ 24.71 | $ 23.97 | $ 23.25 |
| A-1 | $ 29.93 | $ 29.03 | $ 28.16 | $ 27.32 | $ 26.50 | $ 25.70 | $ 24.93 | $ 24.18 | $ 23.46 | $ 22.75 |
| A-6 | $ 29.93 | $ 29.03 | $ 28.16 | $ 27.32 | $ 26.50 | $ 25.70 | $ 24.93 | $ 24.18 | $ 23.46 | $ 22.75 |
| A-10 | $ 31.30 | $ 30.36 | $ 29.45 | $ 28.57 | $ 27.71 | $ 26.88 | $ 26.07 | $ 25.29 | $ 24.53 | $ 23.80 |
| E-19-S | $ 28.80 | $ 27.94 | $ 27.10 | $ 26.28 | $ 25.50 | $ 24.73 | $ 23.99 | $ 23.27 | $ 22.57 | $ 21.89 |
| E-19-P | $ 28.80 | $ 27.94 | $ 27.10 | $ 26.28 | $ 25.50 | $ 24.73 | $ 23.99 | $ 23.27 | $ 22.57 | $ 21.89 |
| E-19-T | $ 28.80 | $ 27.94 | $ 27.10 | $ 26.28 | $ 25.50 | $ 24.73 | $ 23.99 | $ 23.27 | $ 22.57 | $ 21.89 |
| E-20-S | $ 27.44 | $ 26.62 | $ 25.82 | $ 25.04 | $ 24.29 | $ 23.56 | $ 22.86 | $ 22.17 | $ 21.51 | $ 20.86 |
| E-20-P | $ 26.16 | $ 25.38 | $ 24.61 | $ 23.88 | $ 23.16 | $ 22.46 | $ 21.79 | $ 21.14 | $ 20.50 | $ 19.89 |
| E-20-T | $ 24.47 | $ 23.74 | $ 23.02 | $ 22.33 | $ 21.66 | $ 21.01 | $ 20.38 | $ 19.77 | $ 19.18 | $ 18.60 |
| TC-1 | $ 29.93 | $ 29.03 | $ 28.16 | $ 27.32 | $ 26.50 | $ 25.70 | $ 24.93 | $ 24.18 | $ 23.46 | $ 22.75 |
| Ag | $ 26.52 | $ 25.72 | $ 24.95 | $ 24.20 | $ 23.48 | $ 22.77 | $ 22.09 | $ 21.43 | $ 20.78 | $ 20.16 |
| SL | $ 24.61 | $ 23.87 | $ 23.16 | $ 22.46 | $ 21.79 | $ 21.13 | $ 20.50 | $ 19.88 | $ 19.29 | $ 18.71 |

- Annual load growth is assumed at 0.5%

CAISO costs

- CAISO cost: $1.60/MWh
- Distribution losses: 6%
- Scheduling fees: $0.40/MWh

Other costs

- Data Manager Charges of $1.15 per account per month
- Utility Service Fees of $0.37 per account per month

[16] Rate projections are based on current rates which are then projected forward consistent with PEA price assumptions and the resource plans published by the IOUs.

# Exhibit 2 - Pro Forma Summary

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **I. Revenue** | - | 136,673,754 | 139,991,383 | 145,508,839 | 150,681,355 | 160,851,305 | 160,464,456 | 166,135,661 | 172,201,767 | 179,000,514 | 186,876,329 | 193,478,250 |
| **II. Operating Expenses** | | | | | | | | | | | | |
| **Power Supply** | - | 128,306,495 | 132,628,112 | 135,351,263 | 138,439,450 | 142,019,490 | 145,797,478 | 149,106,080 | 152,731,761 | 156,437,792 | 160,282,680 | 163,947,185 |
| **Staff** | 500,000 | 3,075,000 | 3,151,875 | 3,230,672 | 3,311,439 | 3,394,225 | 3,479,080 | 3,566,057 | 3,655,209 | 3,746,589 | 3,840,254 | 3,936,260 |
| **Marketing and Communications** | 291,219 | 1,124,404 | 1,110,563 | 1,138,635 | 1,167,417 | 1,196,928 | 1,227,187 | 1,258,213 | 1,290,025 | 1,322,642 | 1,356,087 | 1,390,378 |
| **Legal, Consulting, other Prof. Services** | 300,000 | 1,537,500 | 1,575,938 | 1,615,336 | 1,655,719 | 1,697,112 | 1,739,540 | 1,783,029 | 1,827,604 | 1,873,294 | 1,920,127 | 1,968,130 |
| **Data Management** | - | 1,414,576 | 1,421,644 | 1,428,748 | 1,435,888 | 1,443,051 | 1,450,264 | 1,457,514 | 1,464,786 | 1,472,095 | 1,479,454 | 1,486,837 |
| **Utility Service Fees** | - | 274,885 | 265,467 | 269,818 | 274,282 | 278,861 | 283,563 | 288,388 | 293,339 | 298,422 | 303,641 | 308,997 |
| **Miscellaneous Admin. & General** | 83,333 | 512,500 | 525,313 | 538,445 | 551,906 | 565,704 | 579,847 | 594,343 | 609,201 | 624,431 | 640,042 | 656,043 |
| **Uncollectibles/Other** | - | 683,369 | 699,957 | 727,544 | 753,407 | 804,257 | 802,322 | 830,678 | 861,009 | 895,003 | 934,382 | 967,391 |
| **Subtotal Operating Expenses** | 1,174,552 | 136,928,729 | 141,378,869 | 144,300,461 | 147,589,509 | 151,399,628 | 155,359,282 | 158,884,302 | 162,732,935 | 166,670,268 | 170,756,666 | 174,661,222 |
| **Operating Margin** | **(1,174,552)** | **(254,975)** | **(1,387,485)** | **1,208,379** | **3,091,846** | **9,451,677** | **5,105,174** | **7,251,359** | **9,468,833** | **12,330,245** | **16,119,662** | **18,817,028** |
| **III. Financing** | | | | | | | | | | | | |
| **Startup Funding Repayment** | 37,500 | 237,500 | 270,000 | 270,000 | 270,000 | 270,000 | 270,000 | 270,000 | 270,000 | 270,000 | 2,732,500 | 6,532,500 |
| **Targeted Reserve Contribution** | - | 5,466,950 | 5,599,655 | 5,820,354 | 6,027,254 | 6,434,052 | 6,418,578 | 6,645,426 | 6,888,071 | 7,160,021 | 7,475,053 | 7,739,130 |
| **Subtotal Financing** | 37,500 | 5,704,450 | 5,869,655 | 6,090,354 | 6,297,254 | 6,704,052 | 6,688,578 | 6,915,426 | 7,158,071 | 7,430,021 | 10,207,553 | 14,271,630 |
| **IV. Total Revenue Requirement** | 1,212,052 | 142,633,179 | 147,248,524 | 150,390,814 | 153,886,763 | 158,103,680 | 162,047,860 | 165,799,729 | 169,891,005 | 174,100,289 | 180,964,220 | 188,932,852 |
| **V. Financing Proceeds** | 2,500,000 | 6,500,000 | - | - | - | - | - | - | - | - | - | - |
| **VI. Actual Reserve Contribution** | 1,287,948 | 6,007,525 | (1,657,485) | 938,379 | 2,821,846 | 9,181,677 | 4,835,174 | 6,981,359 | 9,198,833 | 12,060,245 | 13,387,162 | 12,284,528 |
| **VII. Cumulative Reserve** | 1,287,948 | 7,295,473 | 5,637,988 | 6,576,367 | 9,398,213 | 18,579,890 | 23,415,063 | 30,396,422 | 39,595,255 | 51,655,500 | 65,042,662 | 77,327,191 |
| **VIII. Program Average Rate ($/MWh)** | - | 71.7 | 73.1 | 75.6 | 77.9 | 82.7 | 82.1 | 84.6 | 87.2 | 90.2 | 93.7 | 96.5 |
| **IX. Power Supply ($/MWh)** | - | 67.3 | 69.2 | 70.3 | 71.5 | 73.0 | 74.6 | 75.9 | 77.4 | 78.8 | 80.4 | 81.8 |
| **X. Program Average Cost ($/MWh)** | - | 74.8 | 76.9 | 78.1 | 79.5 | 81.3 | 82.9 | 84.4 | 86.1 | 87.8 | 90.8 | 94.3 |
| **XI. Annual Sales (MWh)** | - | 1,906,431 | 1,915,963 | 1,925,543 | 1,935,170 | 1,944,846 | 1,954,571 | 1,964,343 | 1,974,165 | 1,984,036 | 1,993,956 | 2,003,926 |

# Exhibit 3 - Pro Forma Summary – Residential Only Sensitivity

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **I. Revenue** | - | 40,702,649 | 41,847,791 | 43,411,139 | 44,920,401 | 47,368,130 | 47,865,856 | 49,499,731 | 51,218,324 | 53,084,725 | 55,163,279 | 57,017,732 |
| **II. Operating Expenses** | | | | | | | | | | | | |
| **Power Supply** | - | 32,910,851 | 34,019,007 | 34,735,541 | 35,540,902 | 36,464,989 | 37,438,024 | 38,285,709 | 39,214,066 | 40,162,996 | 41,147,328 | 42,086,178 |
| **Staff** | 300,000 | 1,845,000 | 1,891,125 | 1,938,403 | 1,986,863 | 2,036,535 | 2,087,448 | 2,139,634 | 2,193,125 | 2,247,953 | 2,304,152 | 2,361,756 |
| **Marketing and Communications** | 233,907 | 901,771 | 889,806 | 912,304 | 935,372 | 959,024 | 983,276 | 1,008,143 | 1,033,639 | 1,059,782 | 1,086,588 | 1,114,073 |
| **Legal, Consulting, other Prof. Services** | 300,000 | 1,537,500 | 1,575,938 | 1,615,336 | 1,655,719 | 1,697,112 | 1,739,540 | 1,783,029 | 1,827,604 | 1,873,294 | 1,920,127 | 1,968,130 |
| **Data Management** | - | 1,184,401 | 1,190,318 | 1,196,270 | 1,202,257 | 1,208,264 | 1,214,307 | 1,220,384 | 1,226,483 | 1,232,616 | 1,238,785 | 1,244,975 |
| **Utility Service Fees** | - | 232,041 | 221,885 | 225,478 | 229,165 | 232,947 | 236,829 | 240,813 | 244,901 | 249,097 | 253,406 | 257,827 |
| **Miscellaneous Admin. & General** | 50,000 | 307,500 | 315,188 | 323,067 | 331,144 | 339,422 | 347,908 | 356,606 | 365,521 | 374,659 | 384,025 | 393,626 |
| **Uncollectibles/Other** | - | 203,513 | 209,239 | 217,056 | 224,602 | 236,841 | 239,329 | 247,499 | 256,092 | 265,424 | 275,816 | 285,089 |
| **Subtotal Operating Expenses** | 883,907 | 39,122,579 | 40,312,505 | 41,163,455 | 42,106,024 | 43,175,135 | 44,286,661 | 45,281,816 | 46,361,431 | 47,465,822 | 48,610,227 | 49,711,654 |
| **Operating Margin** | **(883,907)** | **1,580,071** | **1,535,285** | **2,247,684** | **2,814,377** | **4,192,995** | **3,579,195** | **4,217,915** | **4,856,892** | **5,618,903** | **6,553,052** | **7,306,078** |
| **III. Financing** | | | | | | | | | | | | |
| **Startup Funding Repayment** | 37,500 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 75,000 | 2,537,500 | - | - | - |
| **Targeted Reserve Contribution** | - | 1,628,106 | 1,673,912 | 1,736,446 | 1,796,816 | 1,894,725 | 1,914,634 | 1,979,989 | 2,048,733 | 2,123,389 | 2,206,531 | 2,280,709 |
| **Subtotal Financing** | 37,500 | 1,703,106 | 1,748,912 | 1,811,446 | 1,871,816 | 1,969,725 | 1,989,634 | 2,054,989 | 4,586,233 | 2,123,389 | 2,206,531 | 2,280,709 |
| **IV. Total Revenue Requirement** | 921,407 | 40,825,685 | 42,061,417 | 42,974,901 | 43,977,840 | 45,144,860 | 46,276,295 | 47,336,805 | 50,947,664 | 49,589,211 | 50,816,759 | 51,992,364 |
| **V. Financing Proceeds** | 2,500,000 | - | - | - | - | - | - | - | - | - | - | - |
| **VI. Actual Reserve Contribution** | 1,578,593 | 1,505,071 | 1,460,285 | 2,172,684 | 2,739,377 | 4,117,995 | 3,504,195 | 4,142,915 | 2,319,392 | 5,618,903 | 6,553,052 | 7,306,078 |
| **VII. Cumulative Reserve** | 1,578,593 | 3,083,664 | 4,543,949 | 6,716,634 | 9,456,011 | 13,574,006 | 17,078,201 | 21,221,116 | 23,540,508 | 29,159,412 | 35,712,464 | 43,018,542 |
| **VIII. Program Average Rate ($/MWh)** | - | 83.3 | 85.3 | 88.0 | 90.6 | 95.1 | 95.6 | 98.4 | 101.3 | 104.4 | 108.0 | 111.1 |
| **IX. Power Supply ($/MWh)** | - | 67.4 | 69.3 | 70.4 | 71.7 | 73.2 | 74.8 | 76.1 | 77.5 | 79.0 | 80.6 | 82.0 |
| **X. Program Average Cost ($/MWh)** | - | 83.6 | 85.7 | 87.1 | 88.7 | 90.6 | 92.4 | 94.1 | 100.7 | 97.6 | 99.5 | 101.3 |
| **XI. Annual Sales (MWh)** | - | 488,370 | 490,811 | 493,266 | 495,732 | 498,211 | 500,702 | 503,205 | 505,721 | 508,250 | 510,791 | 513,345 |

# ATTACHMENT 2

## Community Choice Energy Program Comparative Matrix

| | SB County Regional CCE | MBCP | CPA | No CCE |
|---|---|---|---|---|
| **Start-Up Cost** | $2.5 M (residential only)<br>$9M (all customers)<br>City pays a portion; can recoup investment to date if launch. | $5,000-$7,500 for update to JPA agreement and Implementation Plan.<br>Cannot recoup investment to date. | TBD,<br>Potentially covered by CPA.<br>Cannot recoup investment to date. | $0<br>Cannot recoup investment to date. |
| **Launch Timing** | 2022 | 2021 | 2022 | N/A |
| **Local Control** | Yes.<br>However, State action may lessen local control of CCEs through resource planning oversight and central procurement. | Limited.<br>Under current governance structure would share one seat on the JPA Board with City of Carpinteria. Governance structure to be re-examined in the coming year.[1] | Limited.<br>One-member, one-vote, with ability for 3 members to request a weighted vote.[2] | No. |
| **Governance Structure** | TBD by JPA. | Policy Board, Operations Board, & Community Advisory Council | Executive Committee, Finance Committee, Energy Committee, & Legislative and Regulatory Committee | N/A |
| **Service Offerings** | TBD by JPA.<br>PEA study modelled 50% Renewable & 75% GHG-free in SCE territory. Rate premium expected for 100% RE option. | Basic (MBchoice): 34% renewable & 100% GHG-free<br>Opt-Up (MBprime): 100% RE for $0.01/kWh rate premium | Lean Power: 36% renewable<br>Clean Power: 50% renewable<br>100% Green Power: 100% renewable | SCE: >40% Renewable & >50% GHG-free |

[1] Current MBCP JPA membership consists of 21 jurisdictions and 12 board seats.
[2] Current CPA JPA membership consists of 31 jurisdictions, with one to be added in 2020.

| | SB County Regional CCE | MBCP | CPA | No CCE |
|---|---|---|---|---|
| **100% Renewable Default Option** | TBD by JPA. | Yes. | Yes, likely will only accept jurisdictions willing to default in at 100% renewable. | TBD based on CPUC Action on SCE's proposed Green Programs. |
| **Rate Impact** | 0% (rate parity); Premium for 100% renewable default estimated at 7-9% based on current CPA experience. | MBchoice: 0% (rate parity) plus rebate; MBprime: $0.01/kWh premium in PG&E territory currently; Premium for 100% renewable in SCE territory estimated at 7-9% based on current CPA experience (TBD). | Premium for 100% renewable is currently 7-9%; estimated by CPA to fall within 5%-10% range. | 0 |
| **Reserve Fund** | 40% of annual operating expenses; projected to be met by year 11 for all customers and year 7 for residential only | 50% of annual operating expenses; projected to be met by late 2020/early 2021. $57 million in reserves as of February 2019. | 30% of total operating expenditures minimum with a maximum target of 50%; not to exceed 60% of total operating expenditures. Estimated $50M in reserves in 2020; projected to be met within 3-5 years. | N/A |
| **Local Program Development** | TBD by JPA. Typically implemented once financial reserve targets reached. | Access to current programs immediately upon enrollment. | Access to current programs immediately upon enrollment. | Existing programs continue (e.g., 3C-REN or SCE offerings) |
| **Local Generation** | Utility-scale: likely no<br>Distributed: longer-term possibility once financial reserve targets reached. | Utility-scale: likely no<br>Distributed: shorter-term possibility through micro-grid program | Utility-scale: likely no<br>Distributed: possible with Clean Energy RFOs and DER pilots in 2020 | Utility-scale: likely no<br>Distributed: possibly pending implementation of Strategic Energy Plan strategies |

| | SB County Regional CCE | MBCP | CPA | No CCE |
|---|---|---|---|---|
| **Staffing (in addition to Board; non-City)** | 10 FTEs (residential only)<br>17 (all customers) | Minimal change expected; possible North County office if SB County and cities join | 17 FTEs<br>Minimal change expected. | 0 |
| **Potential Other Benefits** | • Simplified decision-making and increased local control due to smaller JPA membership | • Depending on rate setting, large PG&E customer base may ameliorate negative impact of SCE's lower generation rates on CCE rates<br>• Faster than creating new program | • Faster than creating new program<br>• Experience with operations in SCE customer service territory | • Funding can be dedicated to other policy priorities |
| **Potential Other Risks** | • Increased financial risk exposure<br>• Fewer resources due to smaller size<br>• Potentially less financial stability due to smaller customer base, reduced purchasing power, and less advantageous credit terms | • New operations in SCE customer service territory | • Largest CCE. Being one of 32 jurisdictions would necessitate active participation in committee structure to affect jurisdictional alignment with CPA policies and programs | • May miss opportunity to offer CCE to community<br>• Will need to rely on SCE programs or RECs to meet 100% RE Goal |

# ATTACHMENT 3

## Monterey Bay Community Power Frequently Asked Questions

# Monterey Bay Community Power Frequently Asked Questions (FAQ)

## Overview

What is MBCP?

Monterey Bay Community Power is a locally-controlled public agency providing carbon-free electricity to residents and businesses in Monterey, San Benito and Santa Cruz Counties as well as the Cities of San Luis Obispo and Morro Bay starting in 2020. MBCP is based on the local energy model called community choice energy that partners with the local utility (in our case PG&E) which continues to provide consolidated billing, power transmission and distribution, customer service and grid maintenance services. PG&E accounts within MBCP's tri-county service area will be automatically enrolled in MBCP's default electric program, unless they choose to opt-out and return to PG&E bundled service at any time. MBCP will match PG&E's electric generation rates, inclusive of any exit fees, and will pay each account holder a minimum 3% rebate currently and MBCP will increase that rebate to 3.7% in 2019.

How does MBCP work with PG&E?

Monterey Bay Community Power works in partnership with PG&E. MBCP assumes responsibility for electric power procurement and purchases clean, carbon-free electricity for homes and businesses in the tri-county area. However, PG&E continues to provide customer billing, receives payments, performs power line maintenance, resolves outages and remains responsible for all gas services. Customers can call either MBCP or PG&E for billing questions.

How did Community Choice Aggregation start?

In response to the effects of energy deregulation in 1997 and the energy crisis that followed in 2000-2001, Assembly Bill 117 was passed by the CA Legislature in 2002 to establish Community Choice Aggregation (CCA) also known as Community Choice Energy (CCE). CCE is a new way for California communities to provide local residents and businesses with a choice of electric providers and sources of electricity. The CCE model enables communities to purchase their own electricity and divert excess revenues to local community investment, rather than to shareholders of investor-owned utilities. There are currently eighteen operational CCEs throughout the state, with many more communities forming their programs. Existing CCEs include: Silicon Valley Clean Energy, serving Santa Clara County; MCE Clean Energy, serving

Marin, Napa and parts of Contra Costa and Solano County; Sonoma Clean Power, serving Sonoma and Mendocino counties; Lancaster Choice Energy, serving the City of Lancaster; CleanPowerSF, serving the city and county of San Francisco; Peninsula Clean Energy, serving San Mateo County; Redwood Coast Energy Authority, serving Humboldt County; and Apple Valley Choice Energy, serving the Town of Apple Valley.

How is MBCP financed?

Monterey Bay Community Power is financed by revenues received from our ratepayers based on the electricity they consume. MBCP is self-funded through existing ratepayer revenues and do not use any tax dollars. As a community agency, any revenues that exceed our costs will be used to cover wholesale energy prices, administrative costs, customer rebates and to benefit the communities we serve through energy programs.

Does MBCP have any debt?

MBCP has successfully paid off a loan obtained through Lines of Credit totaling $6.2 million, as well as reimbursed the County of Santa Cruz for expenses incurred on behalf of MBCP prior to securing the lines of credit.

## Governance

How is MBCP governed?

Monterey Bay Community Power is a joint powers authority, governed by a Policy Board and an Operations Board, each of which includes twelve members. All board members are local elected officials or local government administrators who serve on the board as part of their duties representing their MBCP-member city or county. All board meetings are open to the public, with agendas posted in advance per the Brown Act. Board meeting agendas can be found on our website. MBCP also has a Community Advisory Council which advises and supports the direction of MBCP's energy programs.

Do the cities and counties that make up the Monterey Bay Community Power Authority have any financial risk or obligation for their participation in Monterey Bay Community Power?

No. Monterey Bay Community Power is a Joint Powers Authority (JPA) that functions as a stand-alone public agency. The debts and liabilities of the JPA do not extend to the member cities and counties. This legal firewall is protected by state law.

Is MBCP regulated by the CPUC?

MBCP's energy procurement is regulated by the CPUC like any other electric utility. MBCP rates are set by the board and are not regulated by the CPUC which allows for greater control, savings and local re-investment.

## Billing and Rates

Why do customers have to opt-out instead of opt-in?

California's CCA (Community Choice Aggregation, otherwise known as Community Choice Energy) law requires Monterey Bay Community Power to become the default provider of electric generation for customers within our service area, allowing customers to opt-out and return to PG&E bundled service at any time. If customers opt out after the 60 day enrollment period, they are obligated to stay with PG&E bundled service for the next 12 months.

How are the customers impacted on the billing side?

The cost of electricity generation will be lower to account for PG&E exit fees (aka Power Charge Indifference Adjustment) associated with the change in service. The net result is that electric generation costs will match PG&E's. You will see MBCP's generation charge as a new line item that replaces the same charge from PG&E, as well as the PCIA fee which is absorbed in MBCP's lower generation cost. Customers will see a new page on their PG&E and the MBCP generation charge replaces the PG&E generation charge. Customers will see a generation credit on the Delivery page of the bill.

Are there any additional fees associated with Monterey Bay Community Power Service?

No. PG&E charges Monterey Bay Community Power customers a Power Charge Indifference Adjustment (PCIA). This charge is factored into MBCP's rate setting process so that in total, customers still pay the same as they would under PG&E's generation rates without the fees – zero net increase.

Will discount programs like CARE/FERA/Medical Baseline/LIHEAP continue?

Yes. CARE, FERA, HEAP and Medical Baseline is available to Monterey Bay Community Power customers, as well as PG&E customers, and provides the same discount regardless of enrollment with Monterey Bay Community Power or PG&E. Customers enrolled in Monterey Bay Community Power continue to receive their CARE, FERA, HEAP and Medical Baseline discount within their PG&E delivery charges; there is no need to reapply with Monterey Bay Community Power. New CARE, FERA and Medical Baseline enrollments or renewals must still be done through PG&E's customer service center or website. Any PG&E employee still receives their transmission and distribution discount regardless of electric service provider (ESP).

Am I still eligible for PG&E programs and rebates?

Yes, MBCP customers remain eligible for PG&E rebate programs.

What is MBCP's standard offering and how do I sign up?

MBchoice is Monterey Bay Community Power's standard electricity offering, available automatically to all customers at the time of enrollment. In addition to being carbon-free, MBchoice is classified as 30% renewable, exceeding State requirements. MBCP will provide a minimum 3% rebate for MBchoice customers, to be paid each December for residential customers and either quarterly or biannually for commercial and agricultural customers. You can also select to participate in MBprime, MBCP's 100% renewable energy electric service option or reallocate your rebate towards MBgreen+ or MBshare. MBgreen+ and MBshare provide the same generation service with stronger benefits for the environment and community, automatically funded through the allocation of your rebate and at no cost premium to the customer. No action is needed to be enrolled in MBchoice and keep the customer rebate.

As an MBCP customer, will service reliability be affected?

No, reliability will not be affected. MBCP provides electric generation services, but responsibility for power transmission, distribution, billing and service reliability remains with PG&E. PG&E continues to maintain the power distribution network and repair any outages. PG&E is legally obligated to treat all customers fairly in terms of their transmission and distribution network regardless of who the customer receives electric generation service from.

## Net-Energy-Metering (NEM) Customers

Does Monterey Bay Community Power offer a net energy metering (NEM) program?

Yes. Existing NEM customers will be enrolled in MBCP's Net Energy Metering program for their power generation charges. The program will operate by the same principles as PG&E's NEM program, which remains in effect for the delivery charges and other bill components.

When will NEM customers be enrolled with MBCP?

Since PG&E requires NEM customers to true-up before they enroll with a community choice energy provider, MBCP will automatically place NEM customers in one of four NEM enrollment months closest to their normal true-up date, in order to minimize any potential disruption to the customer's expected NEM value. July 2018 will be the first NEM enrollment month, followed by October 2018, January 2019, and April 2019. If you have any questions or concerns about automatic enrollment, please contact us at 888-909-6227.

Will I keep my NEM 1.0 Grandfathered Status?

Yes. A customer transitioning to service with MBCP will remain grandfathered on the original NEM design if they were on it before switching to MBCP.

What will happen with my PG&E NEM credits if I enroll with Monterey Bay Community Power?

When you become an MBCP customer, you will true-up with PG&E. To minimize any potential lost credits, MBCP has four NEM enrollment months and will automatically place NEM customers in the month closest to their normal true-up date. The first NEM enrollment month is in July. If you have any questions or concerns about automatic enrollment, please contact us at 888-909-6227.

Will MBCP's rates be the same or better than PG&E's for solar customers?

Monterey Bay Community Power solar customers will save money compared to PG&E solar customers. If you are a net consumer of electricity, you will receive a rebate on your electric generation charges from MBCP, set at 3% for 2018. If you are an annual net generator of electricity, MBCP will compensate you at a significantly higher rate than PG&E. MBCP is also adding more consistency to the NSC rate equation by committing to an annual rate. PG&E changes their NSC rate monthly, and as of Feb 2018, customers were paid $.02793 for each kWh of surplus energy. MBCP is more than doubling that rate to **$.06135** which is locked in for the year.

Does Monterey Bay Community Power have an annual true-up like PG&E?

Yes. With Monterey Bay Community Power, customers will continue to have an annual true-up for both MBCP and PG&E charges. The true-up date will be the anniversary of their enrollment with MBCP, instead of the anniversary of their system interconnection. MBCP automatically enrolls solar customers close to their original true-up date in order to minimize disruption to customers.

## Energy Procurement

Where does MBCP procure energy from?

MBCP's energy is procured from carbon-free sources such as solar, wind, biomass and hydroelectric power. The projects that produce our electricity are located in California, and on the western grid. The exact proportion of each varies with time, based on demand and availability. MBCP will have short- and long-term contracts with a variety of power suppliers to meet the energy needs of our community; however, most of MBCP's long-term power contracts will be from CA sources. Monterey Bay Community Power will provide detailed information about its power supply resources in its annual Power Source Disclosure statement. CCEs negotiate the purchase of electricity on the open market by entering into power purchase agreements with energy providers. All energy that is generated is identified by certificates that guarantee the type of energy and location of production. CCEs must also enter into a contract with PG&E to transmit the electricity that the CCE buys over PG&E's transmission lines.

What would MBCP's role be around PG&E's Public Safety Project Shutdown where PG&E cuts power to areas vulnerable to wildfire, heat and wind?

Currently, MBCP has outlined a few positions supportive of the following key initiatives: undergrounding distribution wires and decoupling PG&E from the generation business so they can focus on safety and resiliency of their transmission and distribution system. MBCP is also developing a microgrid model where key customers can unlock economic opportunities through faster and more resilient electric generation and infrastructure.

Why can MBCP get better wholesale pricing than PG&E?

Some may say that CCAs have an unfair advantage over PG&E, given PG&E's higher cost structure, from their existing fixed costs of owned-generating assets along with legacy, higher-priced, power purchases agreements.  The table above dispels this line of reasoning.  MBCP is governed by its Board of Directors, mostly elected, and representing their constituents, MBCP's customers. This is identical to how municipal utilities are governed. PG&E, as an investor-owned-utility (IOU), is a private company with oversight by the California Public Utility Commission. PG&E puts their shareholders ahead of their customers, and the table below confirms that.

| Utility | 2017 Average Rate (cents/kWh) | PG&E's rate is this much higher than Muni's Rate, as a % |
|---|---|---|
| PG&E | 20.06 | |
| City of Santa Clara | 11.68 | 72% |
| City of Palo Alto | 13.29 | 51% |
| City of Alameda | 16.93 | 18% |
| City & County of San Francisco | 11.53 | 74% |
| All California Municipal Utilities | 16.02 | 25% |

*2017 Utility Bundled Retail Sales- Total*
*(Data from forms EIA-861- schedules 4A & 4D and EIA-861S)*

What are MBCP's energy contract terms? How many short term contracts versus long term?

According to our Board-approved Energy Risk Management Policy, MBCP is following industry standard procurement strategies where we have a blend of short & long-term fixed price contracts and will be layering in long-term agreements over time. MBCP executed 3 long-term renewable power purchase agreements in 2018, representing about 20% of our customer load, which will lead to the building of 3 new renewable projects. In fact, one of them, once built will be the largest Solar plus Storage project in California.

Does MBCP buy energy in the spot market and how much?

It is not possible to forecast our customer load/consumption correctly 100% of the time, due primarily to weather uncertainty along with changing and uncertain consumption patterns. Therefore, MBCP does buy energy in the spot market, as do all load serving entities, to cover this load forecasting error and in compliance with our hedging tolerance bands reflected in our Board-approved Energy Risk Management Policy.

How has the PG&E bankruptcy impacted MBCP?

PG&E's bankruptcy deals strictly with restructuring the organization as well as the financial liability of the recent wildfires. The judge presiding over the case has ruled that MBCP revenues are not liable and are viewed as pass through costs.

What is the risk of joining MBCP?

There are regulatory and legislative risks as well as market conditions but those risks also remain with the incumbent investor owner utility. The legislators may be tempted again to bring Direct Access to all consumers, risking the possibility of the return of the energy crisis of 2001.

Is MBCP part of CalPERS?

No. MBCP is part of PARS and doesn't not have any pension liability.

Has MBCP been sued?

No.

How much will it cost to join?

Currently, the cost would be between $5000 to $7500 for each jurisdiction to support the amendment of implementation plan and joint powers authority agreement. This dwarfs the cost of setting up a CCA which generally ranges from $3 to $5 million. This is a small financial cost to be returned significantly in the first year of service not only for the municipal accounts associated with the jurisdictions but for the entire community of customers.