Attachment A

County of Butte, California

Community Choice Aggregation
Initial Feasibility Study

Prepared for:
County of Butte, the Cities of Chico and Oroville, and the Town of Paradise

Prepared by:

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EES Consulting, Inc.

July 17, 2018

Mr. Brian Ring
County of Butte
25 County Center Drive, Suite 200
Oroville, California 95965

SUBJECT: Draft Final CCA Feasibility Study and Business Plan

Dear Mr. Ring:

Please find attached the Final Community Choice Aggregation Study and Business Plan (Plan) for the County of Butte and the Cities of Chico and Oroville and the Town of Paradise (Participants).

It has been a pleasure working for these Participants and we very much appreciate all the effort this working team has spent on the Plan. We look forward to receiving all stakeholder comments after which we will finalize this Plan.

Very truly yours,

Gary Saleba
President/CEO

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Executive Summary

Introduction

This Initial Feasibility and Business Plan ("Plan") evaluates the feasibility of a potential Community Choice Aggregation entity (CCA) for the County of Butte, the Cities of Chico and Oroville, and the Town of Paradise (Participants). This Plan is distinguished from a technical study in that it includes a discussion of governance and operating structure alternatives, whereas a technical study focuses purely on the logistical and financial feasibility of forming a CCA.

Summary of Findings

Based on the assumptions in this study, it is likely that a Butte County CCA will provide rate savings on participant's electric bills. These rate savings are expected to be $5 million annually where all 4 Participants are included in the CCA. These rate savings will have an economic multiplier effect locally creating 42 additional jobs and $1.9 million in labor income within Butte County. Rate savings for the 2 Participant CCA are estimated at $4 million. The uncertainty analysis shows that under a range of reasonable assumptions, a Butte County CCA remains financially feasible.

In addition, the CCA governing board will have local control over power supply choice and local programs that further increase economic development such as investment in energy efficiency or economic development rates. The Participant's CCA could either form a new Joint Powers Authority (JPA) or join an existing JPA. The amount of voting power the Participants will have when joining an existing JPA will vary depending on the JPA organization structure. If forming its own JPA, the Participants will likely have the most voting power and local control. Based on the feasibility analysis and uncertainty results, it is recommended that the Participants continue to pursue a Butte County CCA. The next step would be to incorporate this study's findings into an implementation plan so that the CCA can begin operation after the first quarter of 2020.

CCA Background

CCA legislation has been passed or is being considered in several states. With the passage of California Assembly Bill 117 in 2002, local governments are allowed to form CCAs that offer an alternative electric power option to constituents currently served electric power by investor owned utilities (IOUs). CCAs in California have "opt-out" programs, meaning that customers are automatically placed into CCA service, unless they proactively choose to opt out. Under the CCA model, local governments gain control over their electric power supply and generation sources, while the incumbent IOU continues to provide transmission and distribution service. This gives CCAs the opportunity to reduce retail rates to their constituents, promote local economic development and locally determine power supply fuel mix.

There are currently 18 operating CCAs in California and several more planning to launch in the next two years plus multiple feasibility studies being conducted. The CCAs to date have offered rate discounts on the generation portion of electric utility bills, many have done so an offered a greener mix of power supply compared with the incumbent IOU.

Technical Feasibility Study

The Plan evaluates whether forming a CCA in Butte County could result in retail rate savings while promoting local control and local energy programs, holding low-income customers harmless, and increasing economic development. The feasibility analysis also evaluates other options that a future Butte County CCA may adopt as part of its mission including:

- Increasing the renewable energy content of the power mix to exceed the baseline power mix offered by PG&E. For example, the CCA could purchase long-term renewable contracts or invest in new resource development.
- Delivering power that has a greater share of greenhouse gas (GHG) free resources compared with PG&E. Currently, CCA's accomplish this through hydropower purchases.
- Deliver superior local renewable energy development and energy-efficiency programs. Strategies may include bundling low-income energy efficiency programs with other low-income services, or offering competitive incentives for local renewable resource development or community solar projects.

Once the CCA Participants' goals are refined, adopted, and prioritized, modifications to this Plan may be appropriate.

Feasibility Framework

Financial feasibility is determined by comparing forecast rates for the potential CCA with forecast rates estimated for Pacific Gas & Electric (PG&E). In order to develop forecast CCA rates, load data from PG&E was analyzed and adjusted for participation across rate classes. Using this historic data and forecasts completed by the California Energy Commission, EES Consulting, Inc. (EES) forecasts loads over the study period 2019 through 2030. The load forecast was then used to estimate power supply costs for the CCA. Administrative costs, finance costs, and non-operating costs were also estimated based on loads, customers, and recent CCA experience. Given this information, CCA rates are developed.

PG&E rates are forecast according to current and future resources planned, historic rate changes, among other variables. Retail rate revenue under CCA and under PG&E is compared to determine financial feasibility. A sound financial and operational foundation (such as the development of reserves) for the CCA must be achievable before the other desirable attributes of a CCA can be considered.

Feasibility Results

Based on the assumptions in this study, it is likely that a Butte County CCA will provide rate savings on participant's electric bills. These rate savings are expected to be $5 million annually where all 4 Participants are included in the CCA and the CCA targets a 2% rate savings for its lowest renewable offering of the 3 different options (lowest cost/lowest renewable, moderate renewables/50%, high mix of renewables/75%) Rate savings of $4 million (2% of the PG&E bundled rate) can be expected for a CCA with only 2 Participants (Unincorporated Butte County and the City of Chico). Exhibit ES-1 illustrates the rate savings by jurisdiction and rate class for the 4 Participant scenario.

Exhibit ES-1
Annual Retail Rate Savings
Butte County CCA with RPS Portfolio – 4 Participants

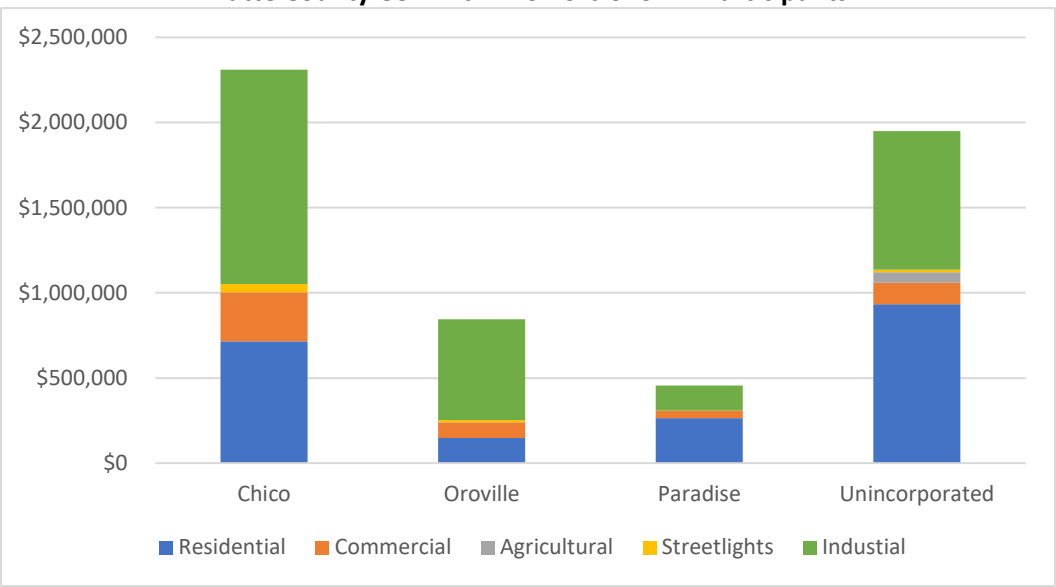
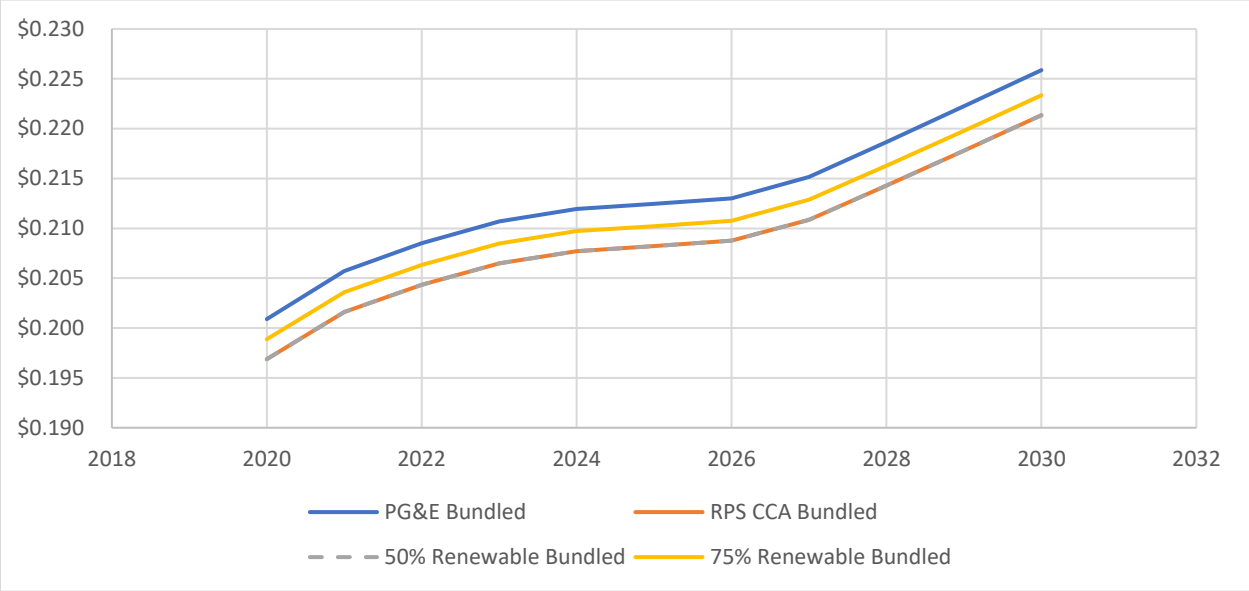


Figure ES-2 shows that PG&E rates are higher compared with the three CCA power supply scenarios modeled: Renewable Portfolio Standard (RPS) CCA Bundled assumes the CCA meet California RPS requirements (currently at 33%); 50% Renewable Bundled assumes the CCA offers power that is 50% renewable; and 75% Renewable Bundled assumes the CCA offers energy that is 75% renewable. The figure illustrates that a Butte County CCA will likely provide retail rate savings even when offering a higher percentage share of renewable energy compared with PG&E.

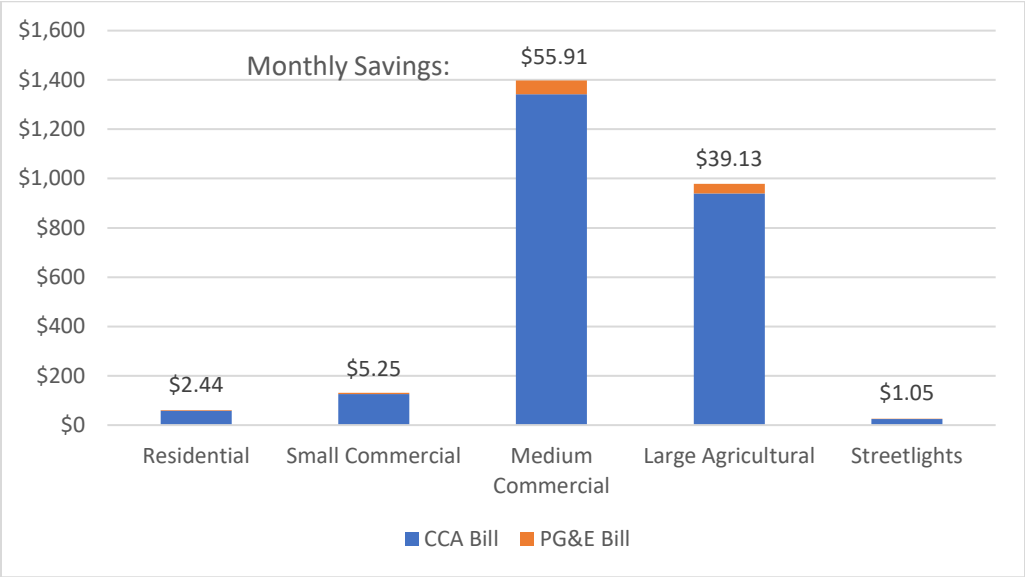
Figure ES-2
Rate Comparison, $/kWh – 4 Participants



Note that the figure above shows CCA rates that target a 2% rate savings for the RPS and 50% renewable case and a 0.5% savings for the 75% renewable case. These rate savings targets are conservative in that the CCA may be able to offer larger rate discounts while covering expenses.

The feasibility analysis found that a Butte County CCA could result in 2% energy rate savings over PG&E bundled rates (generation plus distribution). The figure below illustrates average bill savings for each customer type. In addition to the classes below, the average industrial customer in Butte County would save 0.0034 cents per kWh, or $1,200 per month when usage is 310,000 kWh. There will also be savings to local participating municipalities.

Exhibit ES-3
Monthly Bill Savings, Generation Rate – 4 Participants



Total rate savings estimated for the 4 Participants of the Butte County CCA is $5 million annually. In the 2 Participants scenario (City of Chico and Unincorporated Butte County), rate savings are estimated at $4 million annually.

Potential Cost Savings

The potential to reduce retail rates through CCA has been achieved in other jurisdictions based on the following cost savings:

- Incumbent IOUs have signed long-term contracts for power purchases at a time when the cost of power was significantly higher than it is now. These contracts are for both conventional and renewable generation. Note that this study uses conservative assumptions for power supply costs and the forecast PG&E rate meaning that the PG&E generation rate is escalated at a lower rate than what might be expected and that CCA power supply costs are estimated higher than what can be expected.
- CCAs are small publicly-owned companies that operate with low overhead. Compared with large firms like PG&E, CCAs operate efficiently due to the necessity to provide rate discounts or greener power products at lower cost.
- CCAs do not provide returns to shareholders.

Despite CCA customers paying charges to recover IOU long-term power supply contracts, CCAs are still providing rate savings to their participants. Launched in April 2017, Apple Valley Clean Energy continues to provide rates savings over Southern California Edison (SCE). Rates approved by the Town Council in January 2018 ensures customers will receive a minimum of 3% rates savings on the energy portion of their bill for the remainder of the year. Low income (CARE) customers will receive approximately 13% savings. Additionally, customers who have rooftop

solar (net energy metered, NEM) receive more than double the credit for energy produced compared with the SCE rate schedule.

Valley Clean Energy (VCE) launched in June 2018 serving customers in Yolo County. VCE is targeting 2.5% retail rate savings on the generation portion of PG&E bills. This rate discount is for a product that has a greater share of renewable energy compared with PG&E's resource portfolio.

Lastly, in December 2017, Pioneer Community Energy initially set retail rates at a 3% savings from PG&E bundled rates (generation plus PCIA plus franchise fee). On March 1, 2018 PG&E raised its rates and Pioneer's Board unanimously voted to maintain CCA rates as they were set in the December before. Given the PG&E rate hike, Pioneer customers are saving 9% compared with PG&E customers.

Economic Development

Economic development is another priority for many of the CCAs in California. Local economic development is bolstered through retail rate savings as well as through the locally focused programs offered by the CCAs.

One such program is a special economic development rate to encourage manufacturers or other types of large commercial and industrial industries to site new or expanded operations within the CCA service territory. Additional loads would then bring jobs and tax revenue. The type of new load may also have an impact on average power supply costs. New loads that improve the system load factor will reduce power supply costs and these savings can be passed through to the new large load customer in the form of lower rates. Finally, new large loads may have the flexibility to participate in demand response programs further reducing the average cost of power supply.

Other programs include energy efficiency incentives. PG&E offers a wide range of rebates to businesses across different sectors, including agricultural, computing and data services, food services and refrigeration, HVAC, and lighting.[1] While these rebates would still be available to the CCA's customers, the CCA could offer similar rebate programs better targeted to the business sectors of interest to their service area.

Rate Savings Multiplier Impacts

Bill savings are a major source for local economic development. The IMPLAN model used in the Plan shows the economic impact resulting from $5 million in electric bill savings (the estimated annual rate savings after the 4-participant CCA is in full operation). It is estimated that these

[1]https://www.pge.com/en_US/business/save-energy-money/business-solutions-and-rebates/product-rebates/product-rebates.page

savings will create approximately 42 additional jobs in Butte County and over $1.9 million in labor income.

Local Resource Development

In addition to increased economic activity due to electric bill savings, the Butte County CCA could invest in local renewable projects. These projects can also create job and economic growth within the County and are an option for helping the CCA meet the California renewable portfolio standard. In addition, the Board would retain land use authority where any utility scale solar energy facility would be located.

As an example of the macroeconomic activity caused by local commercial renewable resources, this Plan assumes the installation of 10 crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 10 MW. Overall, the building of a 10 MW solar project is projected to create $17.5 million in earnings and $38 million in output (GDP) in the local economy along with 327 jobs during construction and 3 full-time jobs ongoing. The CCA governing board can consider installing a number of larger local solar projects such as the one described above once reserves are available to fund such projects.

Governance Options

The two most likely options for the Participants are to either form a Joint Powers Authority (JPA) and create a new CCA, or to join an existing CCA/JPA. The amount of voting power the Participants will have when joining an existing JPA will vary.

This plan assumes the Participants would form a stand-alone JPA rather than joining an existing JPA or operating as four single jurisdictions. This governance assumption does not significantly impact the feasibility analysis since operating costs and power supply costs are not expected to be significantly different between the governance structures. Rather, the primary difference in governance structure will be with regard to risk. A JPA can provide a firewall between the CCA and Participants' general funds--financially separating the CCA from other city and county departments.

Operational Structure

In contrast to the governing structures discussed above, the operating structure determines how the CCA will be staffed, managed, and operated. Operation of the CCA will involve a range of day-to-day functions including:

- Marketing and outreach
- Customer service
- Power supply contracts and scheduling
- Billing and data transfer with the IOU / California Independent System Operator (CAISO)

- Regulatory compliance with the California Public Utility Commission (CPUC), California Energy Commission (CEC), and CAISO
- Monitoring regulatory and legislative energy policy relevant to CCA competitiveness

These functions can be fulfilled by internal staff, external consultants, or a mix thereof; and, that mix can change as the CCA becomes fully operational. The choice of how to allocate these functions between internal and external resources through the pre-launch and launch phases is at the discretion of the governing body of the CCA. Existing California CCAs have opted for an organizational structure that, once the CCA is fully operational, is primarily comprised of internal staff with some continued support from consultants once fully operational.

For start-up, the Plan assumes that, under the JPA model, an operating team will be employed consisting of an Interim Executive Director, per the example of other CCAs in California, plus a few other CCA technical staff. This team would then be supported by outside consultants to assist with the management of the CCA until full operations are implemented.

For the longer term, the CCA has two options for after the initial start-up. The first option involves hiring internal staff incrementally to match workloads involved in forming the CCA, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario). In option two, the CCA would hire just a few staff internally and contract out the remaining work to consultants (Minimum Staff Scenario). Throughout the rest of this Plan, it is assumed that the CCA will transition to the Full Staff Scenario. This scenario represents the highest cost scenario to maintain a conservative posture for the Plan's financial pro formas. Less costly options may be available to the CCA based on subsequent work to evaluate other staffing and operational options.

A variation on the Minimum Staff Scenario would be for the CCA's governing body to hire a third-party vendor (sometimes referred to as a "third-party turnkey" approach) or to join an existing CCA to operate the CCA with only three to four internal staff from the Participants acting as program managers. The third-party turnkey operational model is distinct in that the third party would provide financing for the CCA. Under the third-party turnkey approach, the governing body would issue a Request for Proposals (RFP) for the requested services to hire the vendor to operate the CCA. In this scenario, governance of the CCA would remain a responsibility of the CCA.

Risks and Uncertainties

The results of this Plan are subject to uncertainties. These uncertainties are evaluated in the Plan's Sensitivity and Risk Analysis section. The table below provides a summary discussion of the key uncertainties of this Plan. In depth discussion and quantification of risks are provided in the body of the Plan.

Exhibit ES-4
Comparison of Risks, Mitigation Strategies, and Risk Severity

	Risk	Description	Problem	Mitigation Strategy	Likelihood of Problem	Severity of Problem	Potential to "Break" Butte County CCA
1	PG&E Rates and Surcharges	PG&E's generation rates decrease or its non-bypassable charges increase	• Butte County CCA rates exceed PG&E • Increased customer opt-out rate	• Establish Rate Stabilization Fund • Invest in a balanced portfolio to remain agile in power market •Emphasize the value of programs, local control, and environmental impact in marketing	High – most operating CCAs in California have undergone short periods of rate competition from the incumbent IOU.	Medium - CCAs have always been able to buffer rate impacts using financial reserves, then adjust power supply to regain rate advantage.	Low – only in the event of very poor contract management by Butte County CCA and unprecedented changes in IOU rates.
2	Regulatory Risks	Energy policy is enacted that compromises CCA competitiveness or independence	• New costs incurred • Reduced authority	• Coordination with CCA community on regulatory involvement • Hire lobbyists and regulatory representatives	Low – existing regulatory precedent makes the likelihood of state policies that severely disadvantage CCAs low.	High – a worst case scenario regulatory legislative decision limiting CCA autonomy or enforcing additional costs could hinder CCA viability.	Low – energy policy severe enough to make Butte County CCA infeasible is very unlikely.
3	Power Supply Costs	Power prices increase at crucial time for Butte County CCA	• Butte County CCA rates exceed PG&E • Increased customer opt-out rate	• Long-term contracts • Draw on Butte County CCA reserves to stabilize rates through price spike	Low – market prices are unlikely to spike enough to make Butte County CCA financially infeasible prior to CCA launch. From that point on, the CCA can limit its exposure through contract selection.	Medium – a poorly timed price spike combined with poor power supply contract management could require Butte County CCA to dig into reserves or delay launch.	Very low
4	PG&E RPS Share	PG&E's RPS or GHG-free power portfolio grows to match or exceed Butte County CCAs	Increased customer opt-out rate	• Increase renewable power portfolio • Emphasize rates and local programs in marketing	Medium – PG&E's power portfolio is dynamic and could change rapidly as a result of other CCA departures.	Low – CCA will have capability to increase renewable energy purchases to match or exceed PG&E if the event occurs. In addition, Butte County CCA will promote other benefits of its service to customers.	Very Low – CCA is highly likely to respond effectively if this occurs.
5	Availability of RPS/GHG-Free Power	Unexpectedly high market demand or loss of	• Butte County CCA unable to	• Shift emphasis to GHG-free or RPS resources depending on availability	Low – power procurement providers report a	Medium – if Butte County CCA were unexpectedly unable to procure enough	Very Low – negligible chance of occurring.

Exhibit ES-4
Comparison of Risks, Mitigation Strategies, and Risk Severity

	Risk	Description	Problem	Mitigation Strategy	Likelihood of Problem	Severity of Problem	Potential to "Break" Butte County CCA
		supply of renewable resources	provide target power products	• Secure long-term contracts • Invest in local renewable resources	plethora of RPS and GHG-free bids available on the market.	RPS or GHG-free power, it could emphasize other program strengths to retain customers until new resources came online.	
6	Financial Risks	Butte County CCA is unable to acquire desired financing or credit	• Slower or delayed program launch • Unable to build generation projects	• Adopt gradual program roll-out • Establish Rate Stabilization Fund • Minimize overhead costs	Low – CCAs have become sufficiently established in California that financing is almost certainly available.	Medium – in the event Butte County CCA is limited in financing options, it can adopt a more conservative program design and gradual roll-out.	Very Low
7	Loads and Customer Participation	Unprecedented opt-out rate reduces competitiveness	• Excess power contracts • Poor margins	• Increase marketing • Reduce overhead • Expand to new customer markets • Consider merging with existing CCA	Low – as CCAs have become more common in California, and CCA marketing firms more experienced, opt-out rates have gone lower and lower.	Low – Butte County CCA will have numerous viable options in the event they suffer unexpectedly low participation.	Very Low

Financing Options and Risk

Existing CCAs have funded startup costs in different ways; however, the startup costs have been repaid on an average of 18 to 24 months. The CCA market is rapidly expanding with increasingly proven success. To date, there are more than 18 operational CCAs in California that have demonstrated the ability to generate positive operating results. The early financial institutes were community banks in the CCA service territory, but now a mix of regional and large national banks have shown increased levels of interest. This expanded interest should give the CCA comfort that it will have access to an adequate number of potential financial counterparties.

Most programs that have launched to date and those in development have relied on a sponsoring entity to provide support for obtaining needed funds. This support has come in varied forms which are summarized in Exhibit ES-5.

Exhibit ES-5
Forms of Support

CCA Name	Pre-Launch Funding Requirement[1]	Funding Sources
Marin Clean Energy	$2- $5 million	Startup loan from the County of Marin, individual investors, and local community bank loan.
Sonoma Clean Power	$4 - $6 million	Loan from Sonoma County Water Authority as well as loans from a local community bank secured by a Sonoma County General Fund guarantee.
CleanPowerSF	~$5 million	Appropriations from the Hetch Hetchy reserve (SFPUC).
Lancaster Choice Energy	~$2 million	Loan from the City of Lancaster General Fund.
Peninsula Clean Energy	$10 - $12 million	Loans from Barclays County of San Mateo
Silicon Valley Clean Energy	$2.7 million	Loans from County of Santa Clara and City members
Clean Power Alliance	$41 million	$10 million loan from Los Angeles County and $31 million Line of Credit from River City Bank.
East Bay Clean Energy	$50 million	Revolving Line of Credit from Barclays.

[1] Source: Respective entity websites and publicly available information. These funds do not include all funds needed or cover a consistent period.

Start-up financing needs for the CCA are estimated at $3.1 million. A review of the current options for obtaining funds for the startup costs/initial phases is detailed below:

Collateral Arrangement from Butte County or City – As an alternative to a direct loan a CCA Participant, the Participants could establish an escrow account to backstop a lender's exposure to the CCA. The Participants would agree to deposit funds in an interest-bearing escrow account which the lender could tap should the CCA revenues be insufficient to pay the lender directly.

Revenue Bond Financing – This is not a feasible option at this point given the start-up nature of the CCA and no credit rating.

Direct Loan from Butte County or City –The County or City could loan funds from the General Fund for all or a portion of the pre-launch through Phase 1 needs. The County or City would be secured by the CCA revenues once launched. The County or City would likely assess a risk-appropriate rate for such a loan which is likely higher than the County or City earns for funds otherwise invested. This rate is estimated to be 4.0 percent to 6.0 percent per annum.

After start-up additional funding may be obtained through alternative mechanisms including:

Loan from a Financial Institution without Support – Silicon Valley Clean Energy Authority (SVCEA) was able to use this option to fund ongoing working capital. After members funded a total of $2.7 million in start-up funds, SVCEA obtained a $20 million line of credit without collateral.

Vendor Funding – The CCA can pursue arrangements with its power suppliers to eliminate or reduce the need for or size of funding for start-up and operations. This could come in a number of forms such as a "lockbox" approach with a power provider. However, this approach is less transparent and the associated cost may outweigh the benefit of eliminating or reducing the need for a bank facility.

CCA Financing Plan

While there are many options available to the CCA for financing, the initial start-up funding is assumed to be provided via short-term financing. The CCA will recover the principal and interest costs associated with the start-up funding via subsequent retail rates. It is anticipated that the start-up costs will be fully recovered within the first three years of CCA operations. The repayment of start-up costs is based on the cash flow analysis given conservative revenue and expense assumptions made throughout the study. The actual repayment period might be shorter given recent CCA experience where repayment periods average 18 to 24 months.

Phase 1 and Phase 2 of the proposed CCA will require an estimated $6.1 million in capital. Based on recent information regarding financing options for CCAs, the financial analysis assumes that the Butte County CCA will obtain a loan $6.1 million with a term of 5 years at a rate of 5.5 percent. While the term of the loan is assumed to be 5 years, the loan is repaid early by 3 years based on the cash flow analysis.

Introduction

California Assembly Bill 117 allows local governments to form community choice aggregations (CCA) that offer an alternative electric power option to constituents currently served electric power by investor owned utilities (IOUs). CCAs in California have "opt-out" programs, meaning that customers are automatically placed into CCA service, unless they proactively choose not to be. Under the CCA model, local governments gain control over their electric power supply and generation sources, while the incumbent IOU continues to provide transmission and distribution service. This gives CCAs the opportunity to reduce retail rates to their constituents, promote local economic development and use cleaner power supply resources.

This Initial Feasibility and Business Plan ("Plan") evaluates the feasibility of a potential Community Choice Aggregation (CCA) for the County of Butte, the Cities of Chico and Oroville, and the Town of Paradise (Participants). This Plan is distinguished from a technical study in that it includes a discussion of governance and operating structure alternatives, whereas a technical study focuses purely on the logistical and financial feasibility. The potential Participant rates are compared to Pacific Gas & Electric (PG&E) rates. PG&E provided historic energy use data for the Participants' service area. Using this information, EES Consulting, Inc. (EES) estimated the Participants' power supply costs, administrative costs, electric loads, and future retail rates for the Participants and PG&E. These forecast rates are then compared to determine if the proposed CCA can offer competitive rates, better products, and/or superior customer service. A sound financial and operational foundation for the Participants must be achievable before the other desirable attributes of a CCA can be enjoyed.

The Plan assumes four overarching CCA goals for the Participants:

- Reduce retail rates
- Increase economic development in Participants' service territory through special rate classes or other incentives
- Receive a share of CCA revenues for use on local energy programs
- Ensure low-income program offerings are, at minimum, on par with current PG&E offerings

Additional goal options for the board to consider for CCA policy include the following:

- Increase the renewable energy in power mix to exceed the baseline power mix offered by PG&E. For example, the CCA could offer accelerate the rate of renewable resource acquisition, commit to 100% renewable power, or something between.
- Deliver power that has a greater share of greenhouse gas (GHG) free resources compared with PG&E. Currently, CCA's accomplish this through hydropower purchases.
- Deliver superior local renewable energy development and energy-efficiency programs. Strategies may include bundling low-income energy efficiency programs with other low-income services, or offering competitive incentives for local renewable resource development or community solar projects.

While the Participants have not yet officially adopted these goals, they serve as the foundation of this Plan. Once the Participants' goals are refined, adopted, and prioritized, modifications to this Plan may be appropriate.

Plan Methodology

This Plan evaluates the costs and resulting rates of operating a CCA for the Participants and compares these rates to a PG&E rate forecast for the years 2019 through 2029. This pro forma financial analysis models the following cost components:

- Power Supply Costs:
  - Wholesale purchase
  - Renewable purchases
  - Procurement of resource adequacy (RA) capacity (System, Local and Flexible capacity products)
  - Other power supply and charges
- Non-Power Supply Costs:
  - Start-up costs
  - CCA staffing and administration costs
  - Consulting support
  - PG&E and regulatory charges
  - Financing costs
- Pass-Through Charges from PG&E:
  - Transmission and distribution charges
  - Power Cost Indifference Adjustment (PCIA) Charge, Cost Responsibility Surcharge (CRS), Public Purpose Program (PPP) charges and Nuclear Decommissioning Charge (NDC)
  - Franchise Fee Surcharge

The information above is used to determine the retail rates for the CCA. The Participants' CCA rates are then compared to the PG&E projected rates for Butte County CCA service area. After these rate comparisons are made, the attendant economic development and greenhouse gas (GHG) comparisons are made. Operational and governance options are discussed as well as a sensitivity analysis of the key variables contained in the Plan.

Plan Organization

This Plan is organized into the following sections:

- Load Requirements
- Power Supply Strategy and Costs
- Participants' CCA Cost of Service
- Products, Services and Rates Comparison
- Environmental/Economic Considerations

- Sensitivity Analysis
- Summary and Recommendations

Each section is discussed in more detail below.

Load Requirements

The viability of a CCA for the Participants depends in part on the number of customers that participate in the CCA as well as the quantity of energy these customers consume. This section of the Plan provides an overview of these projected values and the methodology used to estimate them.

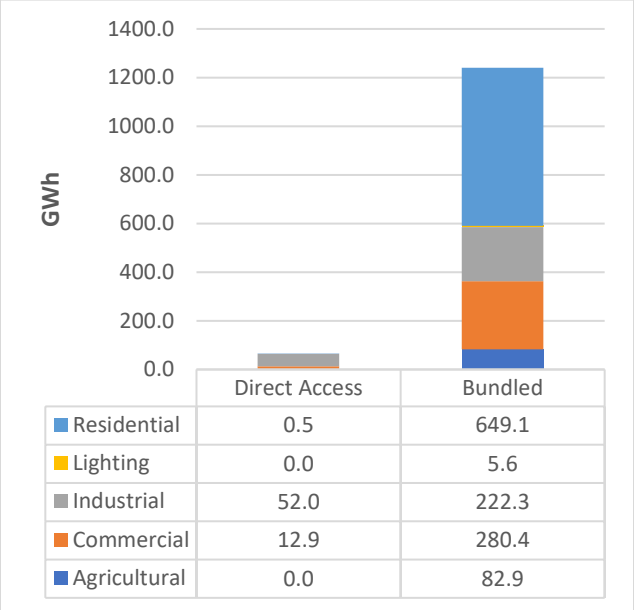
Historical Consumption

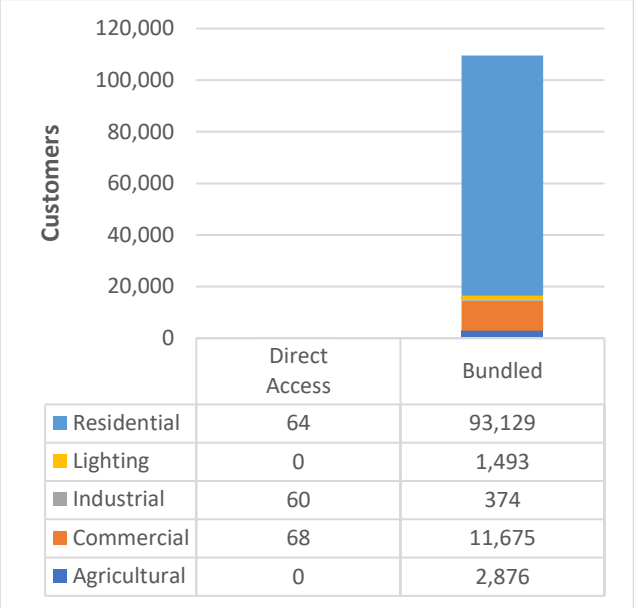
PG&E provided monthly historical data on energy use (kWh) and non-coincident peak load (kW) for each customer in Butte County for the 2016 calendar year. EES aggregated this data by rate class in each month for both bundled (full service) and direct access customers. In total, bundled residents and businesses within unincorporated Butte County, the cities of Chico, Oroville, and the town of Paradise purchased 1,240 GWh of electricity in 2016 from PG&E.

Bundled and Direct Access Customers

Bundled customers currently purchase the electric power, transmission and distribution from PG&E. Direct access (DA) customers buy only the transmission and distribution service from PG&E and purchase power from an independent and competitive Electric Service Provider (ESP). At present, bundled customers make up over 98 percent of total customer accounts in Butte County and 95 percent of the total energy use. DA customers account for 2 percent of customers with just 192 accounts. However, because they are primarily large industrial users, they use nearly 5 percent of the annual energy. Exhibit 1 summarizes energy consumption and number of accounts for bundled and DA customers in 2016.

Exhibit 1
Bundled and Direct Access Load and Accounts in 2016 – 4 Participants





In California, eligibility for DA enrollment is currently limited to non-residential customers and subject to a maximum allowable annual limit for new enrollment measured in gigawatt-hours of new load and managed through an annual lottery.[2] Customers classified as taking service under DA arrangements are not included in this Plan, as it is assumed that these customers will remain with their current Energy Service Provider (ESP).[3]

CCA Participation Rates

Before customers are served by the Participants' CCA, they will receive a total of four notices: two notices with their monthly energy bill 60 and 30 days before the CCA's launch and two notices 30 days and 60 days after the CCA launches. These notices will provide information needed to understand the terms and conditions of service from the Participants' CCA and explain how customers can opt-out, if desired. Notices typically provide a rate comparison between the CCA and the IOU. Customers that opt-out between the initial switchover date and the close of the post enrollment opt-out period will be responsible for the CCA's charges for the time they are served by the CCA, but will not otherwise be subject to any charges for leaving the Participants' CCA. All customers that do not follow the opt-out process specified in the customer

[2] S.B. 286 (CA, 2015-2016 Reg. Sess.)

[3] CPUC rulemaking to date has not addressed how vintage would be handled to DA customers that opt to switch to receive electric power from a CCA rather than their ESP. The most recent ruling on PCIA vintaging was issued on 10/5/2016: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K744/167744142.PDF.

notices prior to launch will be automatically enrolled into the CCA.[4] The CCA would provide a minimum of four opt-out notices to customers to notify and educate them about the CCA's product and their option to opt-out. Customers who wish to opt out may do so electronically or by phone. Customers who opt out after the first 60-day window may not be able to return to PG&E service for one year. After they are returned to PG&E service, customers may be required by PG&E to stay with PG&E for one year. Customers automatically enrolled will continue to have their electric meters read and billed for electric service by PG&E. The CCA bills processed by PG&E will show separate charges for power supply procured by the CCA, all other charges related to delivery of the electricity by PG&E and other utility charges that will continue to be assessed.

This Plan anticipates an overall customer participation rate of 100 percent for the Municipal accounts and 85 percent for the Commercial and Industrial accounts. For residential accounts, it is assumed that approximately 95 percent of customers will remain with the Participants' CCA. These opt-out assumptions are expected based on participation rates in other CCAs. Operating CCAs in California have experienced participation rates ranging from 83% (Marin Clean Energy) to 98% (Peninsula Clean Energy). On average, 90 percent of all potential customers have stayed with their CCA which includes approximately 95% of residential customers staying with CCA service.[5] CCA opt out rates have decreased on average since MCE was the first to form.

Participants' CCA Launch Phases

For this Plan, it is assumed that service will be offered to customers in two phases as noted in Exhibit 2.

Exhibit 2
CCA Load, Customers, and Revenue by Phase – 4 Participants

Phase	Assumed Start	Eligibility	Average Customer Accounts	Total Load (GWh)	Peak Demand (MW)	Normalized Annual Operating Revenues
Phase 1	April 2020	Agricultural, Commercial, Industrial, Lighting	12,000	475	140	$31 million
Phase 2	August 2020	Residential	92,400	1,200	390	$78 million

Data for Phase 2 includes accounts, load, peak, and revenues from previous phases. Estimates assume an 95% and 85% participation rate for residential and non-residential customers respectively. Loads are expressed as wholesale load, including 7 percent transmission and distribution losses. Revenues and loads are presented on an annual basis assuming each phase would be run for a full year. Operating Revenues include CCA costs, Franchise Fee Surcharge, and PG&E's Power Charge Indifference Adjustment (PCIA) charges (See Glossary).

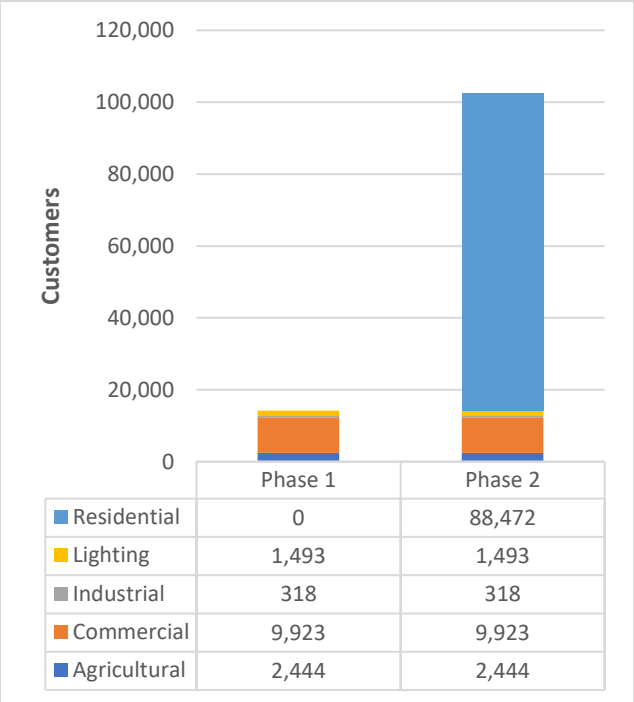
[4] Typically, this doesn't apply to DA customers as the CCA would assume that these customers are not interested in being served by Butte County CCA unless otherwise confirmed prior to launching service.

[5] Average opt-out rate determined based on published number of customers and opt-out rates of Marin Clean Energy, Peninsula Clean Energy, Sonoma Clean Power, Apple Valley Clean Energy, and Lancaster as found at the following document http://www.vvdailypress.com/news/20170818/apple-valley-choice-energy-prompts-thousands-of-customer-calls. Published 8/18/2017; accessed 2/15/2018.

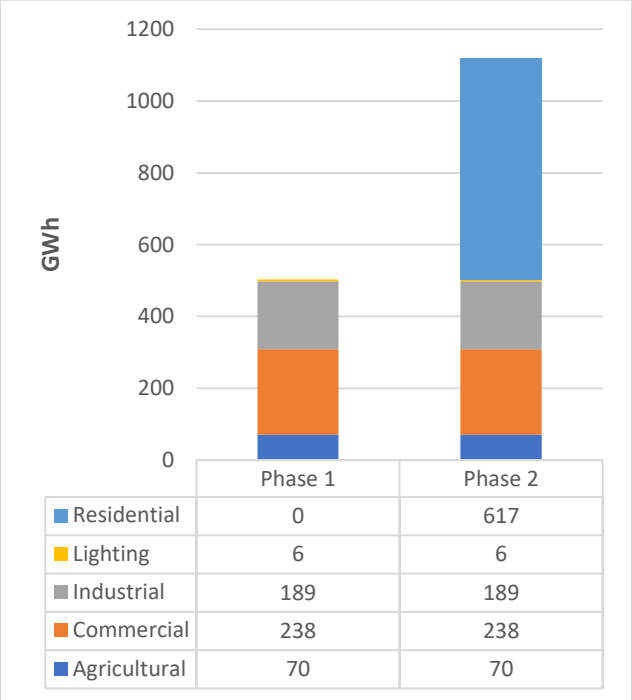
This phasing strategy enables the Participants' CCA to manage any start-up and operational issues before full scale operations commence. In addition, this phasing strategy will allow the CCA's electricity suppliers, scheduling coordinators and data management entities to ramp up power supply procurement and bill processing over several months. It will also likely minimize bad debt expense exposure since lower start-up costs are required in particular with regard to power purchases. Phasing is also expected to have a positive impact on customer participation through demonstrated successful service in early phases.

Data on energy use and number of customers for each phase is displayed in Exhibit 3. Exhibit 4 illustrates the historic monthly load by end-use sector for the accounts in each phase of the CCA's launch.

Exhibit 3
Historic Load and Customers by Phase – 4 Participants

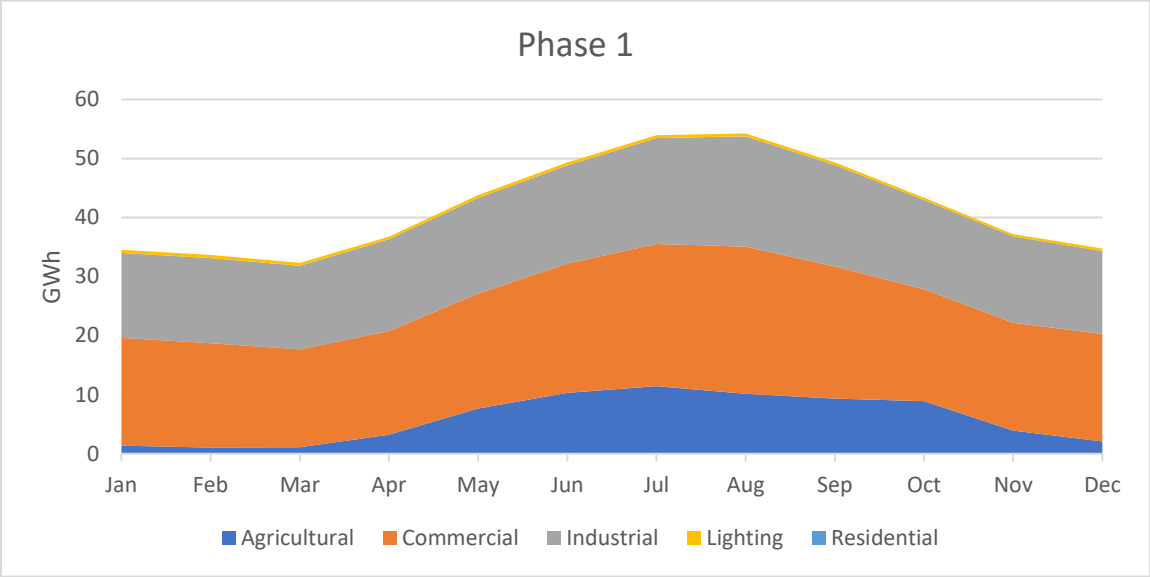


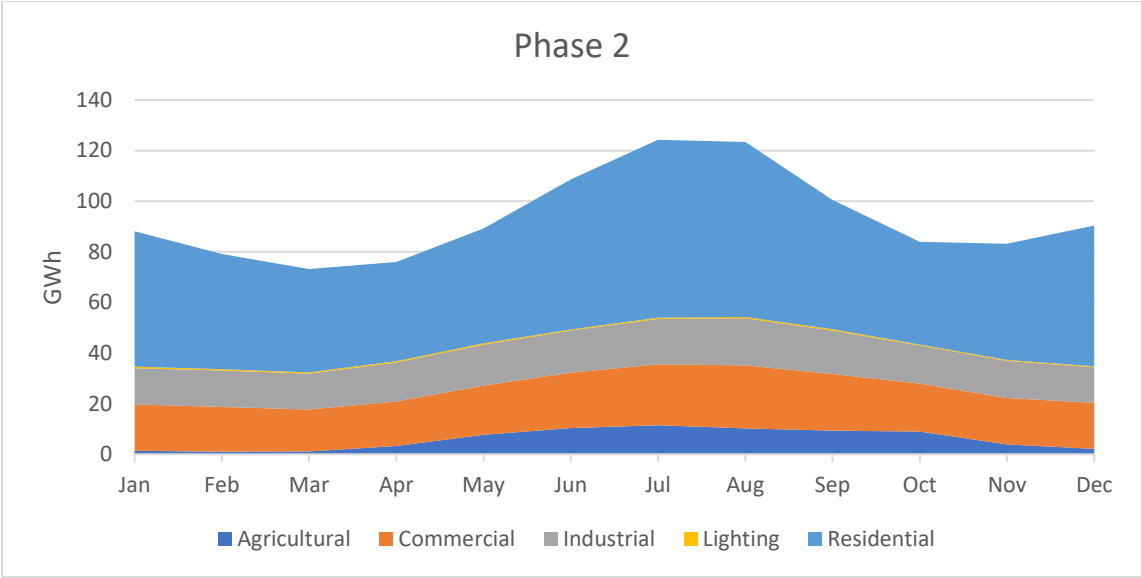
	Phase 1	Phase 2
Residential	0	88,472
Lighting	1,493	1,493
Industrial	318	318
Commercial	9,923	9,923
Agricultural	2,444	2,444



	Phase 1	Phase 2
Residential	0	617
Lighting	6	6
Industrial	189	189
Commercial	238	238
Agricultural	70	70

Exhibit 4
Historic Monthly Load by Phase – 4 Participants



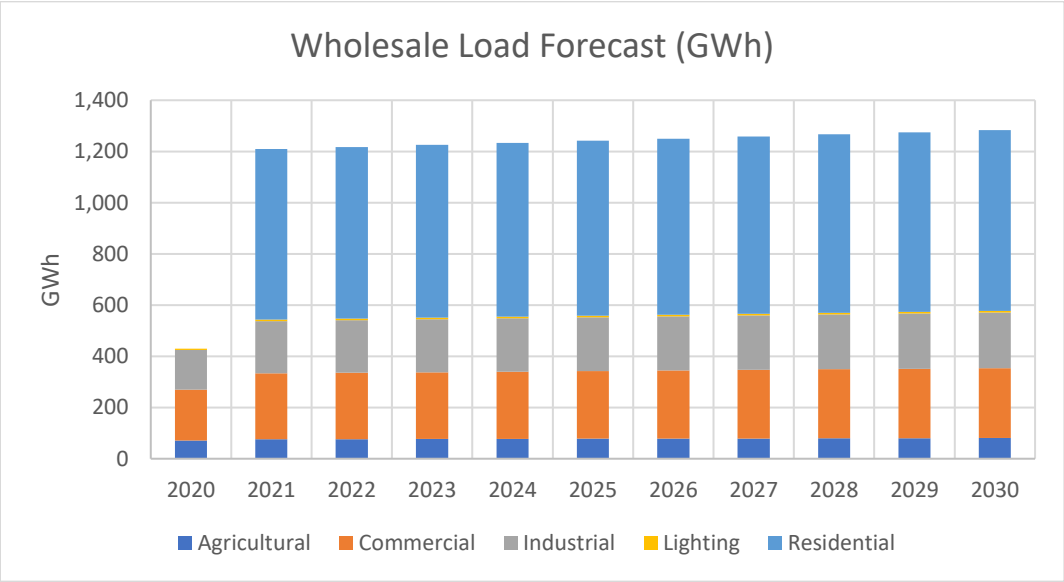


It should be noted that Phase 1 and Phase 2 launch dates for this Plan of April 2020 and August 2020, respectively, have been assumed. The California Public Utilities Commission has recently issued a Resolution 4723 that may delay the Participants' CCA launch until early 2020. The actual impacts of this Resolution and what flexibility it may offer is still being tested and defined. The specific launch date is not expected to significantly impact the financial, environmental and economic development merits of forming a CCA.

Forecast Consumption and Customers

The number of customers enrolled in the CCA and the retail energy they consume are assumed to increase at 0.7 percent per year. This forecast is based on the California Energy Commission's (CEC) mid-demand baseline forecasts for PG&E service territory – Non-Bay Area.[6] Hourly electric consumption and peak demands have been estimated based on PG&E's hourly load profiles for each customer classification. The forecast of load served by the Participants' CCA over the next 12 years is shown in Exhibit 5. This CCA forecast of GWh sales in Exhibit 6 reflects the roll-out and customer enrollment schedule shown previously. Annual wholesale energy requirements are also shown below in Exhibit 6 ("Total Load" column).

Exhibit 5
Projected Load by Sector – 4 Participants



[6] http://www.energy.ca.gov/2017_energypolicy/documents/

Exhibit 6 CCA Projected Annual Energy Requirements (GWh) – 4 Participants			
Year	**Retail Sales**	**Losses[7]**	**Total Load**
2020	650	43	693
2021	1,156	76	1,233
2022	1,164	77	1,241
2023	1,172	77	1,249
2024	1,180	78	1,257
2025	1,187	78	1,266
2026	1,195	79	1,274
2027	1,203	79	1,282
2028	1,211	80	1,291
2029	1,219	80	1,299
2030	1,227	81	1,308

Resource Adequacy Requirements

In addition to determining the base and renewable resource requirements, the CCA will also need to demonstrate it has sufficient physical power supply capacity to meet its projected peak demand plus a 15 percent planning reserve margin. This requirement is in accordance with resource adequacy (RA) regulation administered by the California Public Utilities Commission (CPUC), California Independent System Operator (CAISO) and the California Energy Commission (CEC).

The CPUC's resource adequacy standards require that the CCA demonstrate, one year in advance, that it has secured physical capacity for all of its "local requirements." At this same time the CCA must also demonstrate 90 percent of its procurement obligation for each of the five months May through September, plus a minimum 15 percent reserve margin. On a month-ahead basis, the CCA must demonstrate 100 percent of its procurement obligation of local, system and flexible capacity products. Generally speaking, this reflects a total of 115% of monthly demand, although the specific procurement obligation is determined by the CEC in consultation with the CAISO. The CPUC undertakes annual policy changes to the RA program, so these requirements may change some by the time full program phase-in occurs. Different types of resources have different capacity values for RA compliance purposes, and those values can change by month. Moreover, pending rule changes may have the result of reducing the RA value from wind and solar resource as more of those technologies are added to the system, so other types of renewables, such as geothermal or biomass, could have an overall better value in the portfolio than relying on RA solely from gas-fired resources.

[7] Transmission and Distribution power losses were estimated at 6.6% based on the California Energy Commission's Public Electricity and Natural Gas Demand Forecast published 4/20/2015 at http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN204261-9_20150420T154646_Pacific_Gas_and_Electric_Company's_Notes_re_2015_IEPR_Demand_Fo.pdf.

The Plan's load forecast estimates capacity needs, including RA capacity requirements, to be used in the power supply cost forecasting analysis noted later in this Plan.

Power Supply Strategy and Costs

This section of the Plan discusses the CCA's resource strategy, projected power supply costs, and resource portfolios based on the Participants' CCA projected loads.

Long-term resource planning involves load forecasting and supply planning on a 10- to 20-year time horizon. The Participants' CCA planners will develop integrated resource plans that meet their supply objectives and balance cost, risk, and environmental considerations. Integrated resource planning also considers demand side energy efficiency, demand response programs, and traditional supply options. The Participants' CCA will require staff or a consultant to oversee planning even if the day-to-day supply operations are contracted to third parties. This staff or consultant will ensure that local preferences regarding the future composition of supply and demand resources are planned for, developed, and implemented.

Resource Strategy

The Participants' CCA is interested in minimizing overall energy bills, utilizing revenue as a tool for economic development, meeting renewable energy requirements as mandated by the State. The CCA can achieve these goals in the short-term by taking advantage of relatively low wholesale market prices. As discussed in greater detail below, the CCA's electric portfolio will be guided by the CCA's policymakers with input from its scheduling coordinator and other power supply experts. The scheduling coordinator will obtain sufficient resources each hour to serve all of Butte County CCA customer loads. The CCA policymakers will guide the power supply acquisition philosophy which meets the CCA's policy objectives.

Projected Power Supply Costs

This Plan presents the costs of renewable and non-renewable generating resources as well as power purchase agreements based on current and forecast wholesale market conditions, recently transacted power supply contracts, and a review of the applicable regulatory requirements. In summary, the CCA will need to procure market purchase, renewal purchases, ancillary services and power management/schedule coordinator services. Each of these cost categories is discussed below.

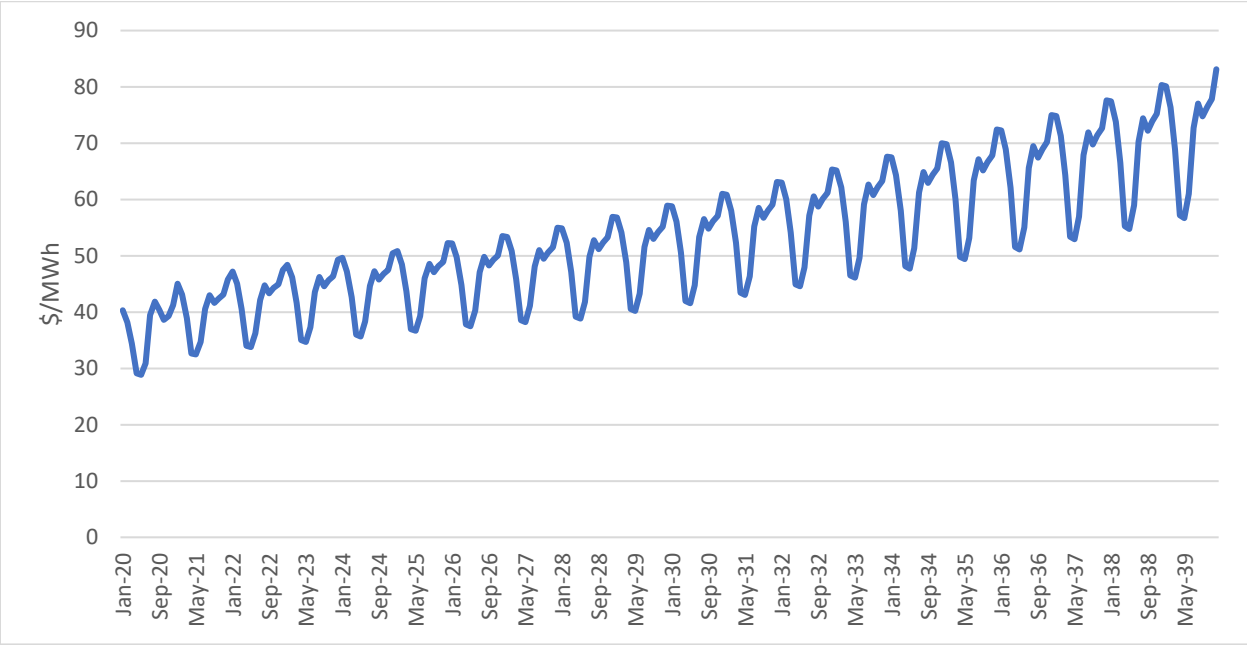
Market Purchases

Market prices for NP15[8] were provided by EES's subscription to a market price forecasting service. An adder of $2/MWh was included in the forecast power purchase agreement (PPA)

[8] NP15 refers to the delivery point north of path 15 where wholesale electricity priced. This is the closest delivery point for power ultimately delivered to Butte County. Deliveries to the Butte County distribution system would require an adder to account for price differentials between the NP15 delivery point and the local Butte County system.

prices to account for basic differences between power delivery at NP15 and delivery at the Butte County local system. An additional adder of $1/MWh was included for a bid/ask spread. Exhibit 7 shows forecast monthly northern California wholesale electric market prices. The levelized value[9] of market prices over the 20-year study period is $51/MWh (2018$) assuming a 4 percent discount rate.

Exhibit 7
Forecast Northern California Wholesale Market Prices



Load balancing purchases and sales have been priced at forecast wholesale power prices. Specifically, when the CCA's loads are greater than its resource capabilities, the CCA's scheduling coordinator will schedule balancing purchases. Similarly, when the CCA's loads are less than its resource capabilities, the CCA's scheduling coordinator will transact balancing sales and the CCA will receive market sales revenue. Balancing market purchases and sales can be transacted on a monthly, daily and hourly pre-schedule basis.

Renewable Energy

The wholesale market prices shown above in Exhibit 7 are for non-renewable power (i.e., this product does not come with any renewable attributes). The cost of renewable resources varies greatly. Wind and solar levelized project costs vary from $35 to $60/MWh. Geothermal project costs can vary from $70 to $100/MWh. While geothermal projects have higher cost, they also have higher capacity factors than wind and solar projects and, as such, can bring additional value to the CCA as baseload resources. Geothermal resources also bring value from a resource

[9] Levelized value, or levelized cost is a calculation that flattens a real or nominal price trend over a period of time. A 20-year levelized cost for the wholesale price of electricity is the market price level over 20 years assuming a discount rate.

adequacy perspective. The availability of off-shore wind and ocean power in the marketplace is fairly minimal, so these resources were not included in this assessment of renewable energy market prices.

This Plan assumes a base case renewable energy market price of $45/MWh for a blend of wind and solar resource contracts, based on a survey of renewable resources currently in operation and new projects coming on-line. Going forward, it is assumed that this price will remain static for the 20-year study period to balance the influence of two trends. First, renewable energy prices are being driven down by the rapidly declining cost of solar and wind projects. This trend has persisted over the past several years and is expected to continue over the Plan's forecast period. However, this trend could be balanced out by the impact of increasing statewide demand for renewables as a result of California's renewable portfolio standards (RPS) laws. These assumptions regarding renewable energy prices have been independently confirmed by current market trends in northern California.

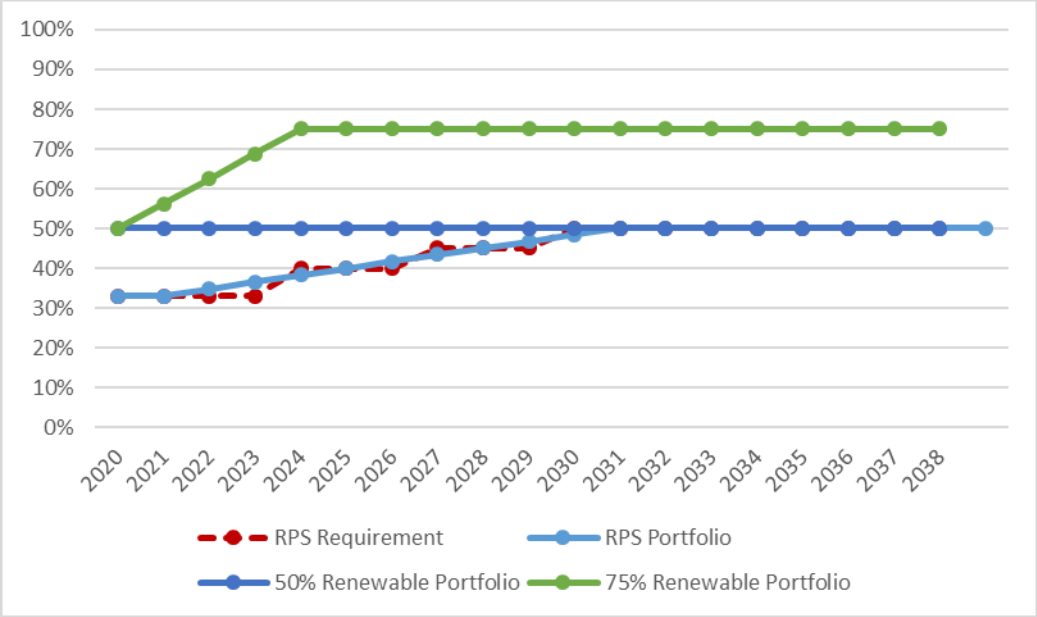
CCA customers are given a choice in their power supply sources or "resource portfolios".

Three resource portfolios are assumed in this Plan for power supply cost modeling contained in this Plan. These resource portfolios are modeled separately for the entire CCA. In practice, CCAs offer different portfolios from which participants select their power supply such that the resulting CCA power mix is a weighted average among 2 or more portfolio options.

1) **RPS Portfolio:** Achieve 33 percent renewables in 2020. Follow the California RPS requirements in all years after 2020, including reaching the 50 percent renewable target in 2030. A linear progression in annual renewable energy purchases, moving toward the RPS targets, is assumed.
2) **50% Renewables Portfolio:** 50 percent of retail loads are served with RPS-qualifying renewable resources in all years.
3) **75% Renewables Portfolio:** 50 percent of retail loads are served with RPS-qualifying renewable resources in 2020. Beginning in 2024, 75 percent of retail loads are served with RPS-qualifying renewable resources. A linear progression in annual renewable energy purchases, moving toward the 75 percent target, is assumed in 2021 through 2024.

The resource portfolios will be discussed in greater detail in the "Resource Portfolios" section below. It should be noted that the CCA policymakers may opt for other resource portfolios but those selected above should give the Participants a sound basis for evaluating other resource portfolio options. The renewable energy targets of the three cases included in the power cost model are shown below in Exhibit 8.

Exhibit 8
Renewable Energy Purchase Scenarios Compared to RPS Requirements[10]



Note: The "RPS Portfolio" line shown above assumes that the CCA would continually increase its renewable portfolio content to meet upcoming RPS requirements. This assumption is necessary to comply with the requirement to show reasonable progress toward the three-year compliance period target. Compliance period requirements are 25 percent in 2019, 33 percent in 2020-23, 40 percent in 2024-26, 45 percent in 2027-29 and 50 percent beginning in 2030. At a minimum, comparability with PG&E is recommended.

Renewable Energy Credits (RECs)

California load serving entities (LSE) must purchase bundled energy and/or renewable energy credits (RECs) that meet certain eligibility requirements across three Portfolio Content Categories (PCC) or buckets. Each of the buckets represents a different type of renewable product that can be used to meet up to a specific percent of the total procurement obligation during a compliance period. The permitted percentage shares of each bucket type changes over time. The three buckets and the type of energy included in each bucket are summarized as follows:

- **Bucket 1**: Bundled renewable resources and RECs – either from resources located in California or out-of-state renewable resources that can meet strict scheduling requirements ensuring deliverability to a California Balancing Authority ("CBA");

[10] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K845/158845742.PDF

- **Bucket 2**: Renewable resources that cannot be delivered into a CBA without some substitution from non-renewable resources.[11] This process of substitution is referred to as "firming and shaping" the energy. The firmed and shaped energy is bundled with Renewable Energy Certificates (RECs).
- **Bucket 3**: Unbundled Renewable Energy Credits (RECs), which are sold separately from the electric energy.[12]

Under the current guidelines, the number of RECs that can be procured through Buckets 2 and 3 are limited and decrease over time. SBX1 2 (April 2011) established a 33 percent RPS requirement by 2020 with certain procurement targets prior to 2020. SBX1 2 also limits the amount of Bucket 3 RECs to 10% of the RPS requirement. SB350 (October 2015) increased the RPS requirement to 50 percent by 2030. Based on these bills, the share of renewable power that can be sourced from Bucket 2 or 3 is expected remain the same over the study period.[13]

Unbundled RECs (Bucket 3) are not viewed as favorably for the development of new renewable power projects. Specifically, purchasing unbundled RECs from existing renewable resources does not substantially incentivize the amount of renewable projects in the State. In addition, the REC market is not as liquid as it once was. For these reasons, this Plan does not rely on unbundled REC purchases to meet renewable energy purchase requirements under the RPS. However, small quantities of unbundled RECs may be used to balance the CCA's annual renewable energy purchase targets with the output from renewable resources. In practice, unbundled RECs may be used as a last effort to help meet the RPS requirement if needed, but only up to 10% of the requirement.

Due to the size and shape of the renewable energy purchases, the annual modeled renewable energy purchases do not match up with annual renewable energy purchase targets down to the REC. In some years there are small REC surpluses and in some years, there are small REC deficits. These surpluses and deficits are balanced out using unbundled REC purchases and sales. This methodology was used in order to simplify the modeling. In reality, small REC surpluses and deficits would most likely be handled by banking RECs between years. For the base case, unbundled REC prices are assumed to increase from $10/REC in 2019 to $20 in 2038 (3.7 percent annual escalation).

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[11] This may occur if a California entity purchases a contract for renewable power from an out of state resource. When that resource cannot fulfill the contract, due to wind or sun intermittency for example, the missing power is compensated with non-renewable resources.

[12] For example, a small business with a solar panel has no RPS compliance obligation, so they use the power from the solar panel, but do not "retire" the REC generated by the solar panel. They can then sell the REC, even though they are not selling the energy associated with it.

[13] California Public Utilities Commission Final Decision, 12/20/2016, accessed at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K457/171457580.PDF, on 1/19/2017.

Ancillary Service Costs

The CCA will pay the CAISO for transmission congestion and ancillary services. Transmission congestion occurs when there is insufficient capacity to meet the demands of all transmission customers. Congestion is managed by the CAISO by charging congestion charges in the day-ahead and real-time markets. The Grid Management Charge (GMC) is the vehicle through which the CAISO recovers its administrative and capital costs from the entities that utilize the CAISO's services.

In addition, because generation is delivered as it is produced and, particularly with respect to renewables can be intermittent, deliveries need to be firmed using ancillary services to meet the CCA's load requirements. Ancillary services and products will need to be purchased from the CAISO based on the total loads served. Based on a survey of transmission congestion and ancillary service costs currently paid by CAISO participants, the Participants' CCA base case ancillary service costs are estimated to be near $2/MWh, escalating by 1.5 percent annually thereafter. Serving a greater percentage of load with renewables will likely result in increased grid congestion and higher ancillary service costs. For this reason, ancillary service costs are assumed to increase with increasing amounts of renewable purchases, up to $4/MWh in the 75% Renewables portfolio (plus 1.5 percent annual escalation).

Power Management/Scheduling Coordinator

Given the likely complexity of the CCA's resource portfolio, the CCA may want to rely on a reputable scheduling coordinator to efficiently manage the CCA's power purchases and wholesale market transactions. The CCA's resource portfolio will ultimately include market purchases, shares of some relatively large power supply projects, as well as shares of smaller, most likely renewable, resources with intermittent output. Managing a diverse resource portfolio with metered loads that will be heavily influenced by distributed generation may be one of the most important functions of the CCA. As such, the Participants' CCA will need to be dependable and have an established scheduling coordinator with a proven track record in the industry. The Participants' scheduling coordinator will be one of its most important business partners.

The CCA should initially contract with a third-party with the necessary experience (and balance sheet) to perform most of the CCA's portfolio operation requirements. This will include the procurement of energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading. Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These activities include the following:

- *Electricity Procurement* – assemble a portfolio of electricity resources to supply the electric needs of the CCA customers.

- *Risk Management* – standard industry risk management techniques will be employed to reduce exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices.

- *Load Forecasting* – develop accurate load forecasts, both long-term for resource planning, and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.

- *Scheduling Coordination* – scheduling and settling electric supply transactions with the CAISO, with related back office functions to confirm PG&E billing to customers.

The Participants' CCA should approve and adopt a set of protocols that will serve as the risk management tools for the CCA and any third-party involved in the CCA portfolio operations. Protocols will define risk management policies and procedures, and a process for ensuring compliance throughout the CCA. During the initial start-up period, the chosen electric suppliers will bear the majority of risks and be responsible for their management. The protocols that cover electricity procurement activities should be developed before operations begin.

A scheduling coordinator provides day-ahead and real-time power and transmission scheduling services. Scheduling coordinators bear the responsibility for accurate and timely load forecasting and resource scheduling including wholesale power purchases and sales required to maintain hourly load/resource balances. A scheduling coordinator needs to provide the marketing expertise and analytical tools required to optimally dispatch the CCA's surplus resources on a monthly, daily, and hourly basis.

The CCA's scheduling coordinator will need to forecast the CCA's hourly loads as well as the CCA's hourly resources including shares of any hydro, wind, solar, and other resources in which the CCA is a participant/purchaser. Forecasting the output of hydro, wind, and solar projects involves more variables than forecasting loads. Scheduling coordinators already have models set up to accurately forecast hourly hydro, wind, and solar generation. Accurate load and resource forecasting will be a key element in assuring the Participants' CCA's power supply costs are minimized.

A scheduling coordinator also needs to provide monthly checkout and after-the-fact reconciliation services. This requires scheduling coordinators to agree on the amount of energy purchased and/or sold and the purchase costs and/or sales revenue associated with each counterparty with which the CCA transacted in a given month.

Based on conversations with scheduling coordinators currently working the CAISO footprint, the estimated cost of scheduling services is in the $0.1 to $0.25/MWh range. This Plan assumes a cost of $0.2/MWh, escalating at 2.5 percent annually, in all portfolios.

Resource Portfolios

Projected power supply costs were developed for three representative resource portfolios. Portfolios are defined by two variables: (1) the share of renewable energy in the power mix (per the "Renewable Energy" discussion above), and (2) the share of resources that are GHG-free in the power mix. Renewable resources refer to resources that qualify under State and Federal RPS, such as solar and wind power. GHG-free power refers to energy sourced from any non-GHG emitting resource, including both the RPS-compliant sources mentioned above as well as nuclear power and large hydroelectric power.

PG&E's resource portfolio currently includes non-renewable energy purchases, renewable energy purchases as well as other non-greenhouse gas (GHG) emitting resources, primarily nuclear and large hydroelectric resources. In 2017, which was a very good year for hydroelectric generation, PG&E's resource portfolio was 79 percent GHG-free.[14] In the "RPS Portfolio" scenario, it is assumed that the Participants' CCA's resource portfolio is 80 percent GHG-free in all years. In the "50% Renewables Portfolio" and the "75% Renewables Portfolio" it is assumed that the CCA's resource portfolio is 80 percent GHG-free in 2019 and 2020 and that the GHG-free resources increase by 1.5 percent each year after 2020 until 2030 when GHG-free resources are 95 percent. The GHG-free resources remain at 95 percent until the end of the Plan's study period (2038).

Last August, PG&E requested approval from the California Public Utilities Commission (CPUC) to retire the Diablo Canyon Power Plant (DCPP), PG&E's only nuclear power generating station[15], by 2025. PG&E's plan would replace the lost generating capacity (roughly 23 percent of all PG&E load[16]) with a mix of energy efficiency and renewable power. This proposal would leave PG&E to select whatever mix of the two resource types is cheapest at the time. For the purposes of this Plan, it is assumed that all power used to replace DCPP will be GHG-free and that PG&E will continue to reduce GHG emissions over that period. In the "RPS Portfolio," the Plan assumes that 65.8 percent of Butte County CCA load is served by GHG-free resources in 2020. As the amount of load served by renewable resources increases each year, so too will the amount of load served by GHG-free resources. This is true of all three portfolios included in the Plan. GHG-free targets for the three portfolios included in the Plan are:

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[14] In 2017, PG&E's resource portfolio was 79% GHG free including 33% from eligible renewable resources plus 46% from nuclear and large hydro.

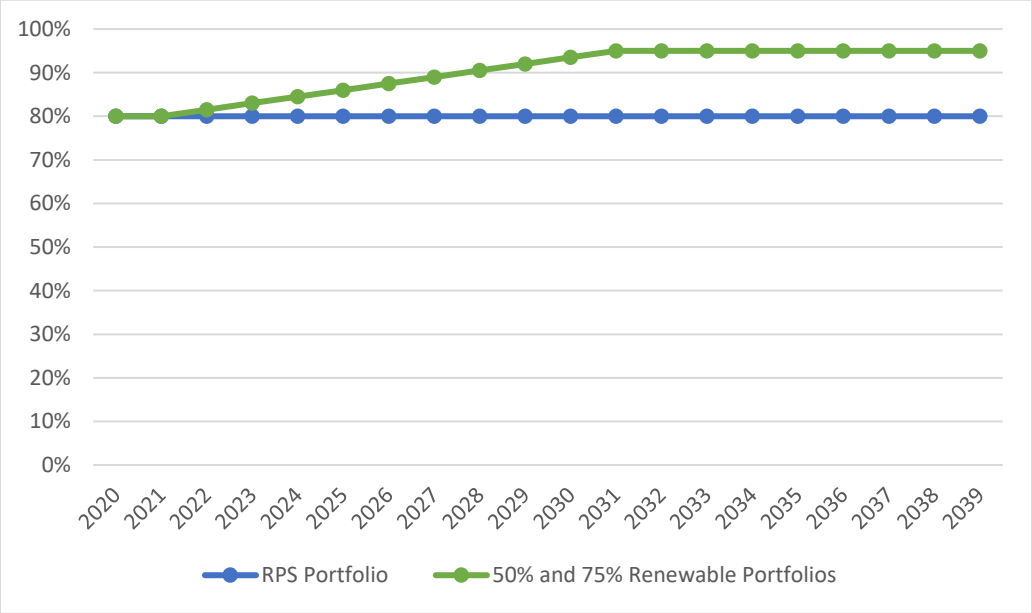
[15] "Application of Pacific Gas and Electric Company (u 39 e) for approval of the retirement of diablo canyon power plant, implementation of the joint proposal, and recovery of associated costs through proposed ratemaking mechanisms." Accessed on 10/18/2016 at:
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M166/K001/166001245.PDF

[16] PG&E website, accessed 10/18/2016 at: https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/clean-energy-solutions/clean-energy-solutions.page

- **RPS Portfolio**: Butte County CCA will match PG&E's projected GHG-free energy supplies.
- **50% Renewable Portfolio**: Butte County CCA will exceed PG&E's projected GHG-free energy supplies by 10 percent each year.
- **75% Renewable Portfolio**: Butte County CCA will exceed PG&E's projected GHG-free energy supplies by 10 percent each year.

It is assumed that the Participants' CCA will not modify its renewable energy or GHG-free achievements to match unexpected or abrupt changes in PG&E's portfolio. Exhibit 9 below shows the GHG-free targets for the resource portfolios.

Exhibit 9
GHG-Free Targets included in Resources Portfolios



In order to achieve the GHG-free targets shown above, it was assumed that a portion of the market power purchases used to serve load in each resource portfolio are sourced to GHG-free resources and that the CCA pays a premium for market PPAs sourced to GHG-free resources. A calendar year 2020 GHG-free premium of $2/MWh was assumed based on a survey of other CCAs. The GHG-premium is assumed to escalate annually by 3.75 percent, the same escalation rate applied to wholesale market prices. Given the assumed escalation rate, the premium paid for GHG-free power increases from $2/MWh in 2020 to $4/MWh in 2039. Including GHG-free premiums in the costs associated with a portion of market PPA purchases results in a $1 to $1.5/MWh increase in the 20-year levelized cost of each portfolio. Again, the portion of market PPAs that are sourced to GHG-free resources in each portfolio is based on the difference between the GHG targets (shown above in Exhibit 9) and the amount of renewable energy procured in each portfolio (shown above in Exhibit 8).

Resource Options

For each of the resource portfolios, a combination of resources has been assumed in order to meet the renewable energy target, resource adequacy targets, and ancillary and balancing requirements. The mix of resources included in each portfolio are for indicative purposes only. The CCA should be flexible in its approach to obtaining the renewable and non-renewable resources necessary to meet these requirements.

Exhibit 10 shows the 20-year levelized resource costs used in this Plan.

Exhibit 10
20-Year Base Case Levelized Resource Costs
(2018 $/MWh)

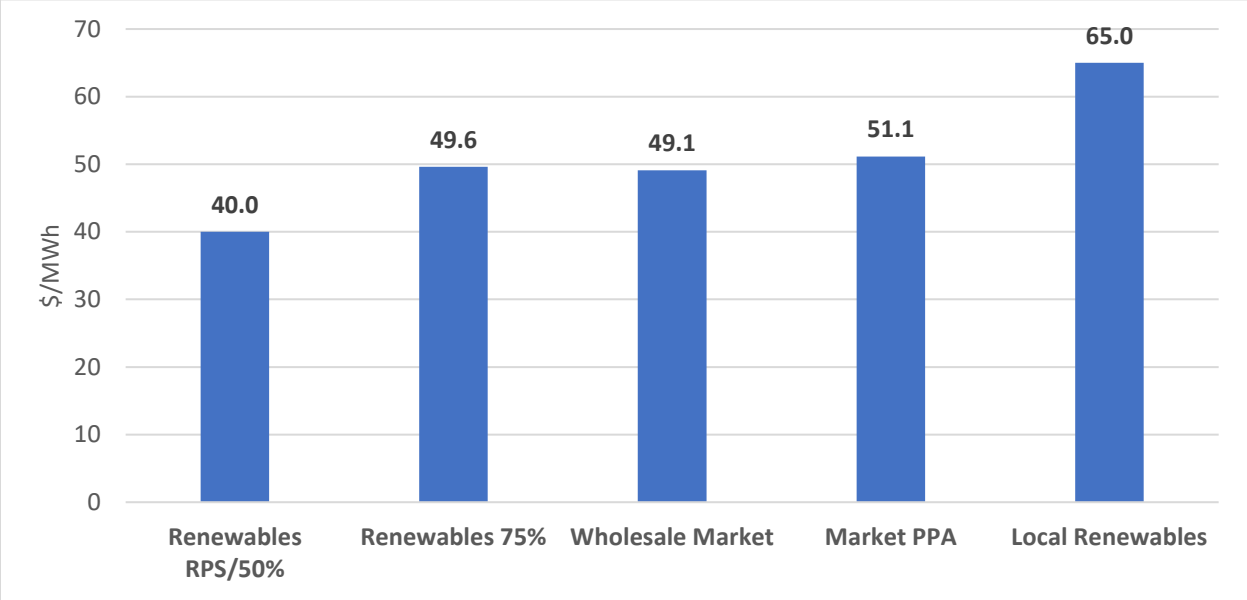


Exhibit 10 above shows a 20-year levelized power purchase agreement (PPA) price of $40/MWh for renewables under the RPS Portfolio and 50% Renewables Portfolio and a price of $49.6/MWh under the 75% Renewables Portfolio. The higher price in the 75% Renewables Portfolio is in recognition of the fact that the CCA may have to sign contracts for higher priced renewables in order to find a sufficient supply of renewables to meet the 75 percent target. The levelized resource costs shown above are for power only and do not include any ancillary services, scheduling or other costs.

Exhibit 10 also shows both spot wholesale market and market PPA costs. Market PPA costs are greater than spot wholesale market costs in recognition of the cost of the PPA supplier absorbing the market fuel price risk associated with providing a long-term PPA contract price.

The capacity factor for market PPA purchases is assumed to be 100 percent (flat monthly blocks of power). Capacity factor is equal to average monthly generation divided by maximum hourly generation in a given month. A 100 percent capacity factor implies that the same amount of

power was purchased or generated each hour. The average monthly capacity factor for renewable resources and local renewables is assumed to be 33 percent based on the capacity factors of existing renewable resources operating in California.

As shown above, the base case 20-year levelized cost of renewable resources is less than the 20-year levelized cost of market purchases. The cost of solar projects has declined significantly over the past few years. The $40/MWh projection is based on the cost of relatively new wind and solar projects that reflect the decreased costs, on a $/watt basis, of solar projects. These cost estimates include changes to federal incentives for renewable resource development. Specifically, the Production Tax Credit (PTC) is set to expire in 2019 while the Investment Tax Credit (ITC), which is available to utility scale solar projects, will ramp down from a 30 percent credit in 2019 to 10 percent credit in 2022 where it will remain. Credit values are based on the resource output. Even with the ramp down of the PTC and ITC, project costs are expected to continue to decrease in future years.[17]

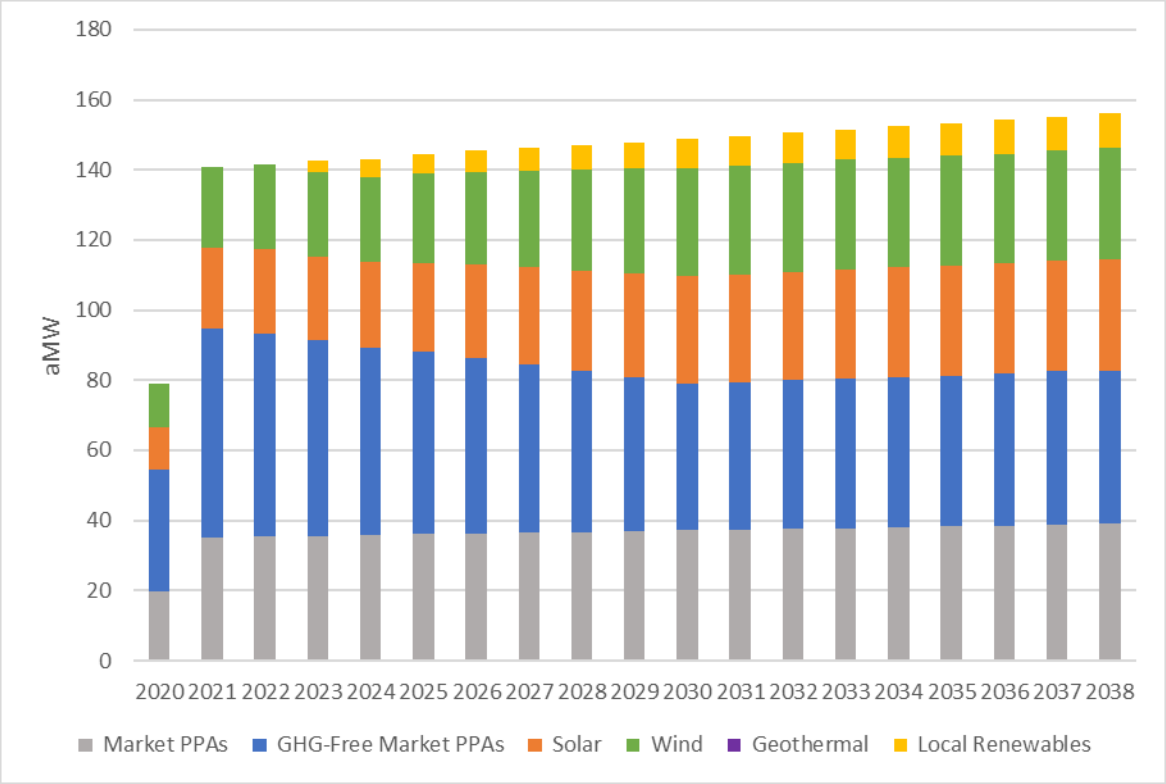
On a $/watt basis, the cost of smaller scale solar projects is greater than the cost of large scale solar projects. The $65/MWh cost associated with local renewables shown in Exhibit 10 reflects this trend. The advantage of local renewable projects is lower transmission costs and less stress on the congested transmission grid.

RPS Portfolio

Exhibit 11 below shows the power supply portfolio used to serve load in the RPS Portfolio scenario

[17] Page 4 of "On the Path to Sunshot: Executive Summary", Solar Technologies Office, U.S. Department of Energy, https://energy.gov/sites/prod/files/2016/05/f31/OTPSS%20-%20Executive%20Summary-508.pdf

Exhibit 11
RPS Portfolio: Meet RPS Targets and Match PG&E's Projected GHG-Free Achievements (aMW)
4 Participants



*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

The share of renewable energy increases each year along with California's RPS requirements. In all three portfolios it is assumed that local renewables will begin serving load in year 5 of operation (2023). It is assumed that 10 percent of renewable energy is purchased via local renewables, as opposed to non-local large-scale renewables, in all three portfolios.

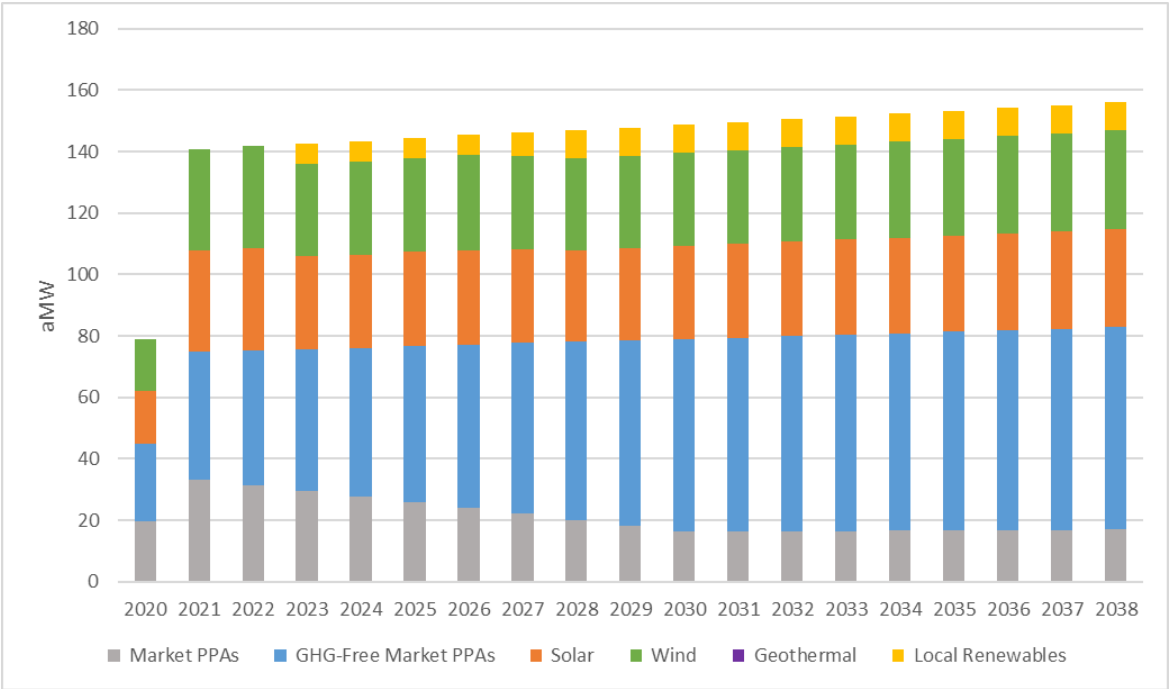
The source of the "market" purchases shown above in Exhibit 11 is unspecified. These market purchases could ultimately be sourced from a mix of renewable and non-renewable resources based on the availability of surplus resources in California and resources bid into CAISO for balancing energy purchases. For this Plan's purposes, "market" purchases are assumed to be sourced to non-renewable generating facilities.

The "GHG-Free Market PPAs" purchases shown above in Exhibit 11 are market purchases that are sourced to hydroelectric generating facilities. These hydro purchases would be procured through long-term PPAs. The cost of hydro power is assumed to be greater than the cost of unspecified market purchases. The premium applied to the cost of hydro power is discussed above in the "Resource Portfolios" section.

50% Renewables Portfolio

In this portfolio, the 50 percent renewable energy purchase requirement in the RPS is effectively moved up 11 years from 2030 to 2020. As shown below in Exhibit 12 the eligible renewable resource purchases (solar, wind, local) are greater than the eligible renewable resources above in Exhibit 11.

Exhibit 12
50% Renewable Portfolio: 50% of Load Served by Renewables in All Years and 95% of Load Served by GHG-Free Resources by 2030 (aMW) – 4 Participants

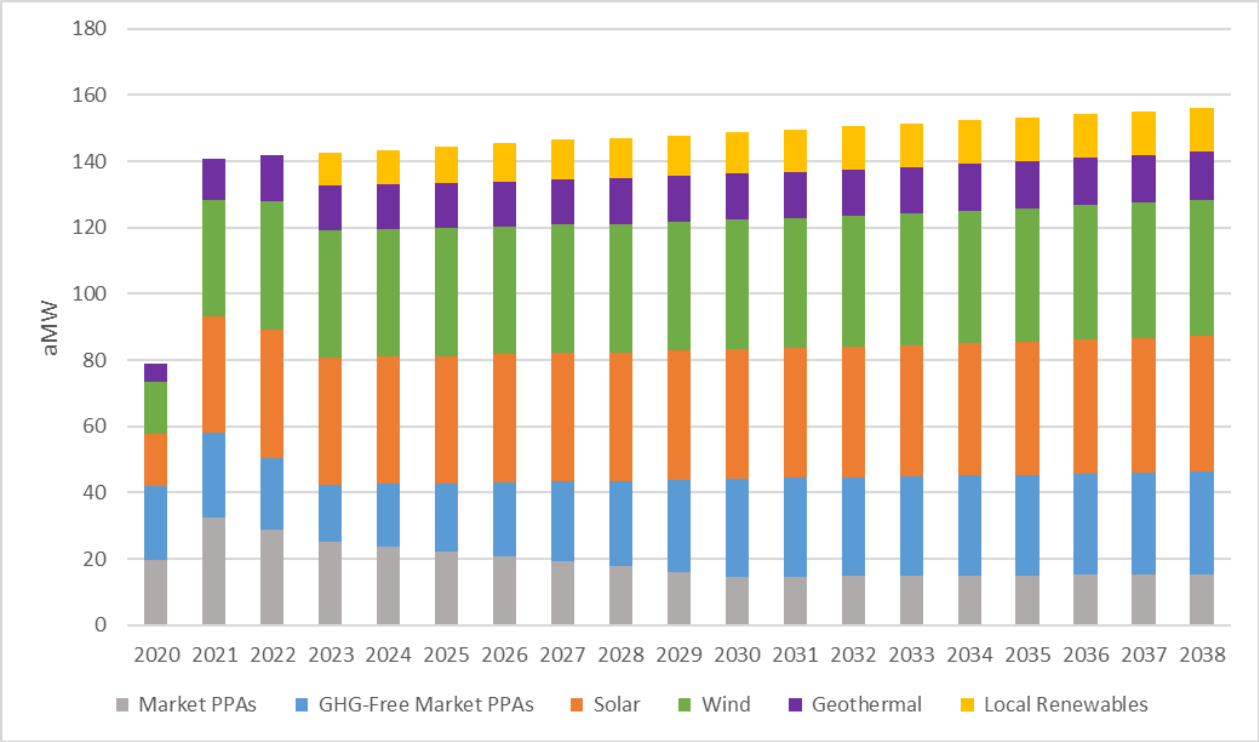


*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

75% Renewables Portfolio

In this portfolio, the 75 percent of retail load is served by renewable resources beginning in 2023. It is assumed that the renewable energy target would begin at 50 percent in 2019 and ramp up to 75 percent by 2023 (as shown in Exhibit 13 below). As shown below in Exhibit 13 the eligible renewable resources (solar, wind, and geothermal) are a larger share of the resource mix compared with the previous two portfolio scenarios.

Exhibit 13
75% Renewable Portfolio: 75% of Load Served by Renewables in All Years and 95% of Load Served by GHG-Free Resources by 2030 (aMW) – 4 Participants

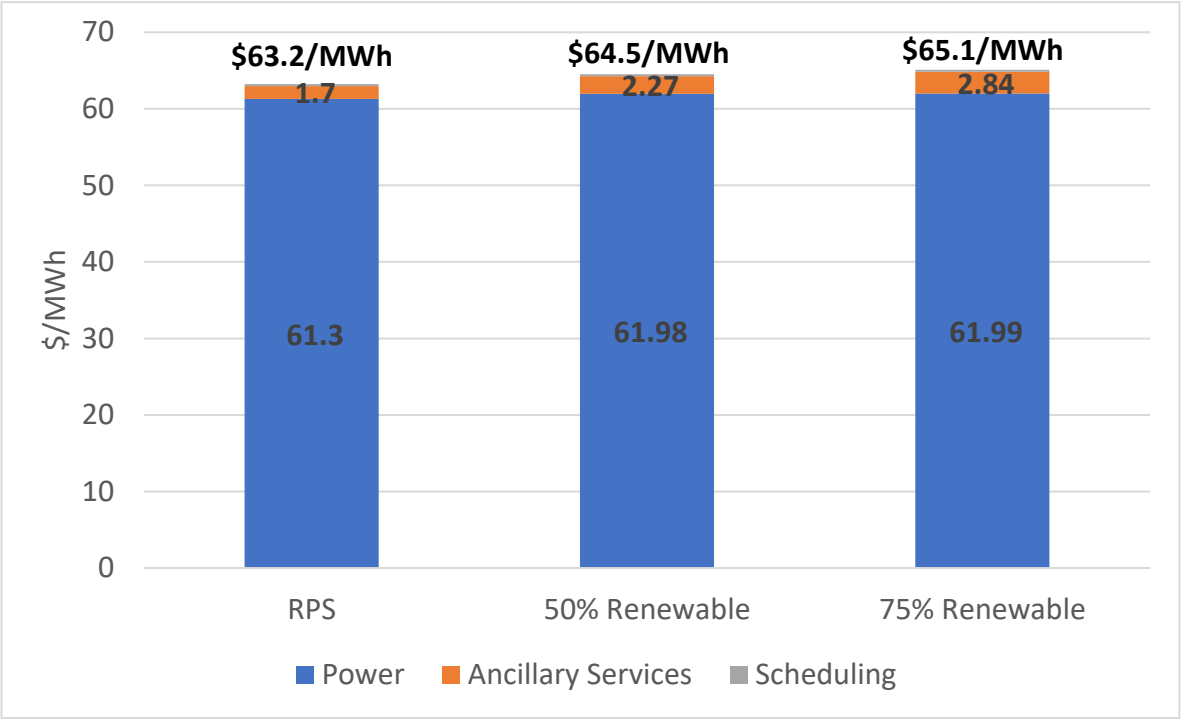


*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

20-Year Levelized Portfolio Costs

The 20-year levelized costs have been calculated based on the base case assumptions detailed above regarding resource costs and resource compositions under the three portfolios. Exhibit 14 shows a breakdown of power, ancillary service and scheduling costs associated with each portfolio.

Exhibit 14
20-year Levelized Base Case Portfolio Costs ($/MWh)



As shown above, power costs under the three portfolios considered are fairly similar. There is not a large variance in power costs between these portfolios because the majority of power is supplied by market PPAs and renewable energy purchases, which are very close in cost.

Resource Strategy

The Participants' electric portfolio may be managed by a third-party vendor, at least during the initial implementation period. Through a power services agreement, the Participants can obtain full service requirements electricity for its customers, including providing for all electric, ancillary services and the scheduling arrangements necessary to provide delivered electricity. After operations have begun, the Participants may decide to sign long-term PPAs, which may minimize the CCAs exposure to market prices and provide the CCA with the ability to increase the renewable percentage over time. Additionally, it is recommended that the Participants engage with a portfolio manager or schedule coordinator, who will have expertise in risk management and will work with the CCA to design a comprehensive risk management strategy for long-term operations. A portfolio manager or schedule coordinator will actively track the CCA's portfolio and implement energy source diversification, monitor trends and changes in economic factors that may impact load, and identify opportunities for dispatchable energy storage systems or automatic controls for managing energy needs in real-time with the CAISO.

Alternative Supply Options

The Participants should plan to establish a Net Energy Metering ("NEM") program for qualified customers in their service territory to encourage Distributed Energy Resources (DER). In addition, the CCA can work with State agencies and PG&E to promote deployment of DER within Butte County, with the goal of maximizing use of the available incentives that are funded through current utility distribution rates and public goods charges. CCAs can provide energy efficiency services as program administrators after they have provided a business plan approved by the CPUC. The funds for the programs come from the electric public benefit charge and can be used for program administration, advertising, and incentives.

The Participants may also establish a program which offers a combination of retail tariffs, rebates, incentives and other bundled offerings intended to increase customer participation in demand-side programs, including renewable DERs, energy storage, energy efficiency, demand response, electric vehicle charging, and other clean energy benefits. The Participants would work with State agencies and PG&E to promote deployment of DERs in specific and targeted locations throughout PG&E's distribution grid in order to help support efficient grid operations and maintenance as part of development of the future "smart grid."

Butte County CCA Cost of Service

This section of the Plan describes the financial pro forma analysis and cost of service for a CCA for the Participants. It includes estimates of staffing and administrative costs, consultant costs, power supply costs, uncollectable charges, and PG&E charges. In addition, it provides an estimate of start-up working capital and longer-term financial needs.

Cost of Service for Butte County CCA "Base Case" Operations

The first category of the pro forma analysis is the cost of service for a CCA for the Participants' operations. To estimate the overall costs associated with CCA operations, the following components have been included:

- Power Supply Costs
- Non-Power Supply Costs
  - Staffing
  - Administrative costs
  - Consulting support
  - PG&E billing and metering charges
  - Uncollectible costs
  - Reserves
  - New programs funding
  - Financing costs
- Pass-Through Charges from PG&E
  - Transmission and distribution charges
  - Power Charge Indifference Adjustment (PCIA) charge
  - Franchise Fee Surcharge

Once the costs of CCA operations have been determined, the total costs can be compared to PG&E's projected rates. A detail of the various costs noted below is included in Appendix C.

Power Supply Costs

A key element of the cost of service analysis is the assumption that electricity will be procured under a power purchase arrangement (PPA) for both renewable and non-renewable power for an initial period. Power supply will likely be obtained by the CCA's procurement consultant prior to commencing operations. The products required from the third-party procurement are energy, capacity (System, Local and Flexible RA products), renewable energy, GHG-free energy, load forecasting, CAISO charges (grid management and congestion), and scheduling coordination.
The calculated 20 year levelized cost of electric power supply, including the cost of the scheduling coordinator and all regulatory power requirements, is estimated between $63 and $65 per MWh.

This price represents the price needed to meet the load requirements of the CCA customers. The variation in price is a function of the desired level of renewable resources.

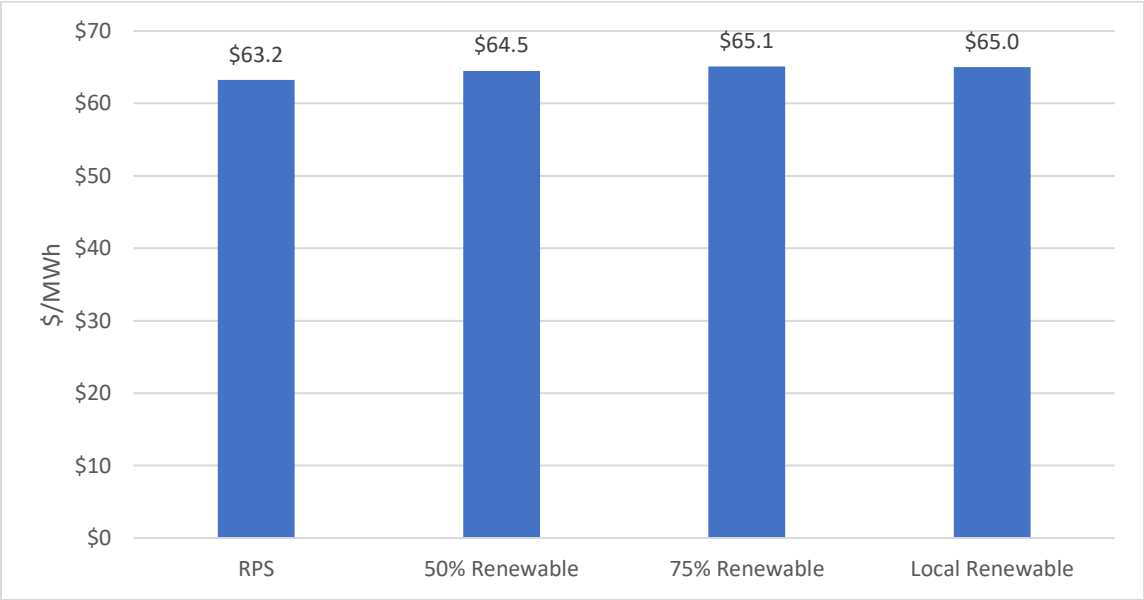
Three power supply scenarios are modeled for this Plan. The three scenarios are:

- Power supply meeting PG&E current RPS plan
- Power supply meeting 50% renewable resources and 80-91% GHG-free
- Power supply meeting 75% renewable resources and 80-91% GHG-free

To further local economic development goals, the Plan assumes that each of the scenarios will include a minimum of 10 MW and a maximum of 30 MW of local renewables. The Plan assumes that "local renewable" power is primarily composed of smaller scale solar projects constructed in Butte County. On a $/watt basis, the cost of small-scale solar projects (assumed to be 500 kW to 5 MW) is approximately $25 per MWh greater than the cost of larger, utility-scale solar projects. A comparison of the three portfolios to the cost of adding in discrete amounts of local renewable is shown in Exhibit 15. Exhibit 15 illustrates that if local renewables are not developed, average power costs will likely be lower.

Exhibit 15

Portfolio and Local Renewables Cost Comparison, 20-Year Levelized



Non-Power Supply Costs

While power supply costs make up the vast majority of costs associated with operating the Participants' CCA (roughly 80-90 percent depending on the portfolio scenario), there are additional cost components that must be considered in the pro forma financial analysis. These additional non-power supply costs are noted below.

Estimated Staffing Costs

Staffing is a key component of the operating a CCA. This Plan assumes the Participants will proceed with the JPA operating model. All staffing, consultant, and infrastructure assumptions are detailed in Exhibits 16, 17 and 18. The Participants' CCA will have discretion to distribute operational and administrative tasks between internal staff and external consultants in any combination. For this Plan, two scenarios are explored that are considered to be at the maximum and minimum of this spectrum. The first option involves hiring internal staff incrementally to match workloads involved in forming the CCA, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario). In the alternative approach, the CCA would hire just three staff internally and contract out the remaining work to consultants (Minimum Staff Scenario). Throughout the rest of this Plan, it is assumed that the Participants' CCA will opt for the Full Staff Scenario to be conservative in the Plan's economic analysis, but both options are discussed. The Full Staff Scenario is likely the most costly option that the CCA could pursue.

Full Staff Scenario

Exhibit 16 provides the estimated staffing budgets for a full staff CCA scenario for the start-up period (Pre-launch in 2020 through full operating in 2021). Staffing budgets include direct salaries and benefits. Prior to the CCA's launch, it is assumed an operating team will be employed per the example of other CCAs in California thus far to implement the launch of the CCA program. This operating team typically includes one Executive Director, Director of Marketing and Public Affairs, and Account Management Staffing. The remaining functions will be filled as quickly as possible.

Exhibit 16 CCA Staffing Plan		
Number of Staff	**2020* Pre-launch**	**2020 Launch Phase 1 and Phase 2**
Executive Director	1	1
Director of Marketing and Public Affairs	1	1
Account Service Manager	1	1
Account Representative	1	1
Communication Specialist	1	1
Director of Power Resources	0	1
Director of Administration and Finance	0	1
Community Outreach Manager	0	1
Power Supply Compliance Specialist	0	1
Administrative Analyst	0	1
Total Number of Employees	**5**	**10**
Total Staffing Costs	**$248,125**	**$1,506,422**

*Represents only partial year.

Based on this staffing plan, the Participants' CCA will initially employ 5 staff members. Once the CCA enters Phase 1, the first phase where the CCA beings to serve load, it is anticipated that staffing will increase to approximately 10 employees. The staffing plan is not expected to change significantly if fewer than four Participants join the CCA. There may be some opportunity to consolidate positions or hire third party assistance, this is discussed in more detail below. The management positions to be hired by the CCA over the first year are described below:

Executive Director

The Executive Director will be responsible for all aspects of launching and operating a highly-visible start-up organization and building it into an innovative enterprise that benefits Butte County residents and businesses. The Executive Director will direct all activities of the Butte County CCA including operations, resource procurement and planning, energy infrastructure development, finance, legal and regulatory affairs, external communications and strategic planning. The Executive Director will report to the CCA's Board and will work with numerous stakeholders including County residents, businesses, labor representatives, government officials, and experts in the fields of energy and utility services.

Director of Power Supply

The Director of Power Supply will oversee the day-to-day power supply operation of the CCA. In particular, this staff position will oversee hedging and power procurement, resource portfolio strategy and other resource planning and compliance analysis. Behind-the-meter CCA programs will also be coordinated through this position.

Director of Administration and Finance

The Director of Administration and Finance oversees the CCA's budgets and accounting functions. In addition, this person will develop annual budgets, rates, and credit policies for approval by the governing body. Managing the overall financial aspects of the CCA is expected to be a significant work activity.

Director of Marketing and Public Affairs

The Director of Marketing and Public Affairs is responsible for the enrollment and notification of new customers. In addition, this staff person will market the CCA, and provide ongoing communication with the CCA's communities and customers. A significant amount of customer service and key account representation will be necessary in addition to regular marketing services. This position will be the point person for the outsourced data management and customer service consultants.

Future Staff

As additional customers join the CCA, duties can be shifted from third-party consultants to in-house staff if internal staffing is desired and/or more cost effective and as directed by CCA management.

Minimum Staff Scenario

To build the minimum staff possible to run the Participants' CCA, all tasks described above would be completed by consultants on a contract basis. It is assumed that these contracts would be managed by the Executive Director and two in-house staff, such as the Regulatory and Finance managers. In addition, consultants would have to be hired to manage the tasks not managed by full-time staff. It is anticipated that the cost difference between all-in staff cost and consultant cost is minimal. The projected savings difference under each option are therefore not anticipated to be significant.

Administrative Costs

Infrastructure or overhead needed to support the organization includes computers and other equipment, office furnishings, office space, utilities and miscellaneous expenses. These expenses are estimated at $70,000 during program pre-startup for the full staffing scenario. Office space and utilities are ongoing monthly expenses that will begin to accrue before revenues from program operations commence and are therefore assumed to be financed. If existing County office space is available at a lesser price[18], rates will be lower and CCA-related savings higher.

[18] If the CCA function is housed in a city or county building, then it will need to pay its prorated share of debt service for any associated bonds

It is estimated that the per employee start-up cost is approximately $7,000. This expense covers computer and furniture needs. An additional annual expense of $15,000 for office space, and approximately $10,000 per year in office supplies and utilities costs is expected. Miscellaneous start-up costs of $100,000 are estimated for 2019 to address the general cost of mailing notifications, meetings, communication and other start-up activities. In addition, it is assumed that computers will need to be replaced every 5 years. Finally, additional miscellaneous expense budgets are estimated for general start-up costs in 2019. All administrative costs for start-up are shown in Exhibit 17.

Exhibit 17
Estimated Infrastructure Cost by Year (Full-Staff Scenario)

	2020	2021
Infrastructure Costs		
Computers	$50,000	$0
Furnishings	$20,000	$0
Office Space	$15,000	$15,300
Utilities/Other Office Supplies	$10,000	$10,200
Miscellaneous Expenses	$100,000	$100,000
Total Infrastructure Costs	**$195,000**	**$127,500**

While the minimal staffing option would save some infrastructure costs, it is anticipated that the consultant staff would include similar cost. It is therefore not anticipated that the minimal staff option would result in any significant cost differences.

Outside Consultant Costs

Consultant costs include outside assistance for legal and regulatory work, communication and marketing, data management, financial consulting, technical consulting and implementation support. CCA data management providers supply customer management system software, and oversee customer enrollment, customer service, as well as the payment processing, accounts receivable and verification services. In addition, estimated funding for other consulting support (such as HR, legal, customer service, etc.) is provided. Exhibit 18 shows the estimated consultant costs during the first three years. Assumptions about consultant fees are provided on a monthly and annual basis in Appendix C.

Exhibit 18
Estimated Consultant Costs by Year

	2020	2021	2022
Legal/Regulatory*	$270,000	$367,200	$374,544
Communication	$183,333	$102,000	$104,040
Financial Consulting**	$500,000	$510,000	$520,200
Technical Consultant	$120,000	$122,400	$124,848
Other Consulting/County Functions	$300,000	$153,000	$156,060
Total Consultant Costs	**$1,448,333**	**$1,356,600**	**$1,383,732**

*Legal/regulatory consulting refers only to legal counsel regarding CPUC compliance, filings, etc.
**Financial consulting includes legal fees for counsel on CCA financing.

The estimate for each of the services is based on costs experienced by other CCAs. Consultant costs are increased by inflation every year. It should be noted that these costs are estimated for the Full Staff Scenario. Under the Minimal Staff Scenario, consultant costs are increased such that total CCA operational costs remain the same under each staffing scenario.

PG&E Billing & Metering Costs

PG&E provides billing and metering services to the CCA based on published tariffs. The estimated costs payable to PG&E for services related to the Participants' CCA start-up include costs associated with initiating service with PG&E, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees.

Customers who establish service with the CCA will be automatically enrolled in the program and have 60 days from the date of enrollment to customer opt-out of the program. Such customers will be provided with two opt-out notices within this 60-day post enrollment period. The first notice will be mailed to customers approximately 60 days prior to the date of automatic enrollment. A second notice will be sent approximately 30 days later. Following automatic enrollment, two additional opt-out notices will be provided within the 60-day period following customer enrollment. A total of four notices will be sent to each customer. It is estimated that the billing charges will be approximately $0.25 million for 2020 and $0.56 million for 2021, as shown in Exhibit 19. These transaction fees assume all 4 Participants are included in the CCA.

Exhibit 19
Utility Transaction Fees – 4 Participants

	2020	2021	2022
Total PG&E Transaction Fees	$252,845	$559,142	$562,832

Uncollectible Costs

As part of the operating costs, the CCA must account for customers that do not pay their electric bill. While PG&E will attempt to collect funds, approximately 0.5 percent of revenues are estimated as uncollectible.[19] This cost is therefore added to the CCA revenue requirement or budget.

Financial Reserves

The Participants' CCA is assumed to receive capital financing during its start-up through Phase 2 (Phase 2 is where all customer classes are now being served by the CCA). After a successful launch, the CCA must build up a reserve fund that is available to address contingencies, cost

[19] Based on historic IOU uncollectible revenue as percent of total revenue.

uncertainties, rate stabilization or other risk management factors faced by the CCA. Therefore, this Plan assumes that the CCA will begin building its reserve starting from its launch. After five full operating years, it is estimated that the assumed rate will have accumulated enough reserve for three months of expenses. This level of reserves is based on industry standards for electric utilities, and will provide financial stability and assist the CCA in obtaining favorable interest rates if additional financing is needed. After that point, revenues that exceed costs can begin to finance a rate stabilization fund, new local renewable resources, additional economic development projects and/or lower rates. These financial reserves, assuming all 4 Participants form the CCA, are documented in Appendix B.

New Programs/Projects Costs

Once the reserve fund has reached its target, the revenue requirement includes budget for new customer programs including local renewable resources projects, distributed generation support, additional energy efficiency program offering, etc. Rate design programs, such as Net Energy Metering and Economic Development rates, can be implemented sooner as these do not require large capital investments.

Financing Costs

In order to estimate financing costs, a detailed analysis of working capital needs as well as start-up capital is estimated. Each component is discussed below.

Cash Flow Analysis and Working Capital

This cash flow analysis estimates the level of working capital that will be required until full operation of the CCA is achieved. For the purposes of this Plan, it is assumed that the CCA pre-operations begin in January 2019. In general, the components of the cash flow analysis can be summarized into two distinct categories: (1) Cost of the CCA operations, and (2) Revenues from CCA operations. The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with the CCA and specifically account for the transition or "phase-in" of the CCA customers. The cash flow analysis assumes the phase-in schedule for Butte County CCA shown in Exhibit 20.

Exhibit 20 Launch Schedule – 4 Participants				
Phase	**Start**	**Eligibility**	**Total Accounts Served**	**Percentage of Total Load Served**
1	April 2020	Commercial, Industrial, Lighting, & Agriculture	14,000	45%
2	August 2020	Residential	88,500	55%

The cash flow analysis also provides estimates for revenues generated from the CCA operations or from electricity sales to customers. In determining the level of revenues, the cash flow analysis assumes the customer phase-in schedule noted above, and assumes that Butte County CCA provides a discount of the existing PG&E rates for each customer class that corresponds to a total bill discount of 2%.

The results of the cash flow analysis provide an estimate of the level of working capital required for the CCA to move through the pre-operations period. This estimated level of working capital is determined by examining the monthly cumulative net cash flows (revenues minus cost of operations) based on assumptions for payment of costs by the CCA, along with an assumption for when customer payments will be received. The cash flow analysis assumes that customers will make payments within 60 days of the service month, and that the CCA will make payments to suppliers within 30 days of the service month. This analysis is somewhat conservative because customer payments begin to come in soon after the bill is issued, and most are received before the due date. At the same time, some customer payments are received well after the due date. The 30-day net lag is a conservative assumption for cash flow purposes.

For purposes of determining working capital requirements related to power purchases, the CCA will be responsible for providing the working capital needed to support electricity procurement unless the electricity provider can provide the working capital as part of the contract services. In addition, the CCA will be obligated to meet working capital requirements related to program management. While the CCA may be able to utilize a line of credit, for this Plan it is assumed that this working capital requirement is included in the financing associated with start-up funding.

A summary of working capital needs is presented below on Exhibit 21. Working capital line items are described in more detail below the Exhibit.

Exhibit 21 Working Capital Needs – 4 Participants		
	2020 Pre-Launch/Phase 1	**2020 Launch Phase 2**
Bonding & Security Requirement (CPUC)	$0.1 million	-
PG&E Program Reserve	$0.4 million	-
Start-up Costs	$1.3 million	-
Working Capital (Cash Flow)	$1.3 million	$3 million
Total Capital Needed	**$3.1 million**	**$3 million**

- Bonding & Security Requirement (CPUC) – Insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to PG&E service under certain circumstances.
- PG&E Program Reserve – Required and equivalent to reentry fee for voluntary returns to the IOU.
- Start-up Costs – Includes capital for staffing, consultants, office infrastructure and building, collateral, or other start-up costs.
- Working Capital – requirements to ensure positive cash flow so that there is not gap between power bill payment and retail rate revenue delivery.

For comparison, Marin Clean Energy (MCE) started with $3.3 million in pre-launch funding[20] and is now operating with $21.7 million in working capital.[21] MCE serves electrical load roughly equivalent to 3.5 percent of Butte County CCA's estimated load.[22] Similarly, Sonoma Clean Power (SCP) acquired $6.2 million in pre-launch capital,[23] and now maintains working capital reserves of $25 million[24] while serving five percent of the CCA's estimated load.[25] Because all CCA's are exposed to similar levels of fixed costs at launch, the pre-launch funding in Sonoma and MCE's cases are close to that calculated for Butte County CCA. The working capital needs after launch assumed in this Plan are in line with the experience of successfully operating CCAs on a $/GWh basis.

[20]https://www.mcecleanenergy.org/wp-content/uploads/2016/01/MCE-Start-Up-Timeline-and-Initial-Funding-Sources-10-6-14-1.pdf
[21]https://www.mcecleanenergy.org/wp-content/uploads/2016/09/MCE-Audited-Financial-Statements-2015-2016.pdf
[22]https://www.mcecleanenergy.org/wp-content/uploads/2016/01/Marin-Clean-Energy-2015-Integrated-Resource-Plan_FINAL-BOARD-APPROVED.pdf
[23] https://sonomacleanpower.org/wp-content/uploads/2015/01/2014-SCPA-Audited-Financials.pdf
[24] https://sonomacleanpower.org/wp-content/uploads/2015/01/2016-05-SCP-Compiled-Financial-Statements.pdf
[25] https://sonomacleanpower.org/wp-content/uploads/2015/01/2015-SCP-Implementation-Plan.pdf

Total Financing Requirements

The start-up of the Participants' CCA will require a significant amount of start-up capital for three major functions: (1) staffing and consultant costs; (2) infrastructure costs (office space, computers, etc.) and (3) CPUC Bond and PG&E security deposits.

Staffing, consultant and other program initiation costs have been discussed previously. In addition, the Public Utilities Code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to PG&E service under certain circumstances. PG&E also requires a bond equivalent to the reentry fee for voluntary returns to the IOU. This corresponds to the fees outlined in the CCA-SF rate schedule from PG&E, which are $4.24/customer for 2018. In addition, the bond must also cover incremental procurement costs.

For the Participants' CCA, the total financing requirement, including working capital, during the pre-launch to full operations, are estimated to be approximately $3.1 million, with approximately another $3 million following full enrollment. With more flexible power payment terms and/or customer payments of less than 60 days, capital requirements can be reduced by up to $3 million.

Current CCA Funding Landscape

The CCA market is rapidly expanding with increasingly proven success. To date, there are more than 18 operational CCAs in California that have demonstrated the ability to generate positive operating results. The early financial institutes were community banks in the CCA service territory, but now a mix of regional and large national banks have shown increased levels of interest. This expanded interest should give the CCA comfort that it will have access to an adequate number of potential financial counterparties.

As CCAs have successfully launched across the State and a more robust data set of opt-out history becomes available, the financial community has been more comfortable in providing credit support to CCAs. Most programs that have launched to date and those in development have relied on a sponsoring entity to provide support for obtaining needed funds. This support has come in varied forms which are summarized in Exhibit 22.

Exhibit 22 Forms of Support		
CCA Name	**Pre-Launch Funding Requirement[1]**	**Funding Sources**
Marin Clean Energy	$2- $5 million	Startup loan from the County of Marin, individual investors, and local community bank loan.
Sonoma Clean Power	$4 - $6 million	Loan from Sonoma County Water Authority as well as loans from a local community bank secured by a Sonoma County General Fund guarantee.
CleanPowerSF	~$5 million	Appropriations from the Hetch Hetchy reserve (SFPUC).
Lancaster Choice Energy	~$2 million	Loan from the City of Lancaster General Fund.
Peninsula Clean Energy	$10 - $12 million	Loans from Barclays and San Mateo County.
Silicon Valley Clean Energy	$2.7 million	Loans from County of Santa Clara and City members
Clean Power Alliance	$41 million	$10 million loan from Los Angeles County and $31 million Line of Credit from River City Bank.
East Bay Clean Energy	$50 million	Revolving Line of Credit from Barclays.

[1] Source: Respective entity websites and publicly available information. These funds do not include all funds needed or cover a consistent period.

Start-up financing needs for the CCA are estimated at $3.1 million. A review of the current options for obtaining funds for the startup costs/initial phases is detailed below:

Collateral Arrangement from Butte County or City – As an alternative to a direct loan a CCA Participant, the Participants could establish an escrow account to backstop a lender's exposure to the CCA. The Participants would agree to deposit funds in an interest-bearing escrow account which the lender could tap should the CCA revenues be insufficient to pay the lender directly.

Revenue Bond Financing – This is not a feasible option at this point given the start-up nature of the CCA and no credit rating.

Direct Loan from Butte County or City –The County or City could loan funds from the General Fund for all or a portion of the pre-launch through Phase 1 needs. The County or City would be secured by the CCA revenues once launched. The County or City would likely assess a risk-appropriate rate for such a loan which is likely higher than the County or City earns for funds otherwise invested. This rate is estimated to be 4.0 percent to 6.0 percent per annum.

After start-up additional funding may be obtained through alternative mechanisms including:

Loan from a Financial Institution without Support – Silicon Valley Clean Energy Authority (SVCEA) was able to use this option to fund ongoing working capital. After members funded a total of $2.7 million in start-up funds, SVCEA obtained a $20 million line of credit without collateral.

Vendor Funding – The CCA can pursue arrangements with its power suppliers to eliminate or reduce the need for or size of funding for start-up and operations. This could come in a number of forms such as a "lockbox" approach with a power provider. However, this approach is less

transparent and the associated cost may outweigh the benefit of eliminating or reducing the need for a bank facility.

CCA Financing Plan

While there are many options available to the CCA for financing, the initial start-up funding is assumed to be provided via short-term financing. The CCA will recover the principal and interest costs associated with the start-up funding via subsequent retail rates. It is anticipated that the start-up costs will be fully recovered within the first three years of CCA operations.

The anticipated start-up and working capital requirements for the Participants' CCA through Phase 1 are approximately $3.1 million. Once the CCA program is operational, these costs would be recovered through retail rates. Actual recovery of these costs will be dependent on third-party electricity purchase prices and decisions regarding initial rates for Phase 1 customers.

Additional financing will be needed at the beginning of Phase 2. Depending on market conditions and payment terms established with the third-party suppliers, the loan may need to be increased to approximately $6.1 million (an additional $3 million over the start-up and Phase 1 needs) for the start of Phase 2. This number will be refined as the CCA program becomes operational and bids are received from power providers. In addition, the actual repayment period might be shorter given recent CCA experience where repayment periods average 18 to 24 months.

Based on recent information regarding financing options for CCA's, this financial analysis assumes that the CCA can obtain a loan for all $6.1 million with a term of 5 years at a rate of 5.5 percent. While the term of the loan is assumed to be 5 years, the repayment period assumed is 3 years.

The detail of the base case cash flow analysis is provided in Appendix D.

Products, Services, Rates Comparison and Environmental/Economic Impacts

This section provides a comparison of service and rates between PG&E and the Participants' CCA. Rates are evaluated based on the CCA's total electric total bundled rates as compared to PG&E's total bundled rates. Total bundled electric rates include the rates charged by the CCA, including non-bypassable charges, plus PG&E's delivery charges

Rates Paid by PG&E Bundled Customers

The average customer-weighted PG&E rates have been calculated based on current rate schedules and the CCA's projected customer mix. PG&E's current rates and surcharges have been applied to customer load data aggregated by major rate schedules to form the basis for the PG&E rate forecast.

The average PG&E delivery rate, which is paid by both PG&E bundled customers and Butte County CCA customers, has been calculated based on the forecasted customer mix for the Participants' CCA. For future years, the PG&E rate forecast assumes the delivery costs will increase by 2 percent per year, a conservative assumption given the history of PG&E non-power supply rate increases.

Similarly, the current average power supply rate component for PG&E bundled customers has been calculated based on the estimated CCA customer mix. Finally, the PG&E generation rates have been projected to increase based on the renewable and non-renewable market price forecast, regulatory requirement for RPS, storage requirement, and resource adequacy objectives. It is projected that PG&E-owned resource and renewable escalation will be 0% over the 10-year analysis period, due to Diablo Canyon Nuclear Plant retirement and departing load. PG&E's renewable supply will also grow with the combination of these two factors, and the escalation in the PCIA will slow. It is projected that the main contributors to PG&E's rate increase over time will be market price and variable cost increases. This results in an average annual escalation rate of 0.3 percent over the 10-year analysis period, a conservative assumption. This resultant PG&E power cost and trend is consistent with similar forecasts provided in other CCA feasibility studies.

Rates Paid by CCA Customers

It is anticipated that the CCA's rate designs will initially mirror the structure of PG&E's rates so that similar rates can be provided to CCA's customers and bill comparisons can be made on an apples-to-apples basis. PG&E is moving towards Time-of-Use (TOU) rates for all customers and it is assumed that the CCA will follow this transition initially. In determining the level of CCA rates,

the financial analysis assumes the customer phase-in schedule noted above and that the implementation phase costs are financed via start-up loans.

In addition to paying the CCA's power supply rate, CCA customers will pay the PG&E delivery rate and non-bypassable charges. The non-bypassable charges that are payable to PG&E by the Participants' CCA customers include:

- Power Charge Indifference Adjustment (PCIA)
- Franchise Fee Surcharge

Power Charge Indifference Adjustment

The PCIA is a charge that is designed to keep bundled customers indifferent when other customers leave bundled service and cover any of the IOU's (in this case PG&E) stranded costs associated with unavoidable generation-related costs purchased on behalf of the departing CCA customers. The PCIA is calculated annually by subtracting the market price of wholesale power from the incumbent utility's average cost of power supply in place at the time the CCA customer leaves PG&E based on a methodology determined by the CPUC.[26] The CPUC oversees the calculation and methodology every year as part of the annual ERRA process. The CCA can participate in this process and provide input and objections as needed.

For this Plan, it was assumed in the base case that the PCIA increases by 20 percent annually over the 2018 level for 2019 and 2020. Post-2020, the PCIA is expected to grow based on the inverse of the difference in the growth between PG&E's generation cost and market prices. The PCIA is calculated based on the difference between PG&E's surplus resource cost and the market price. Therefore, as market prices increase more than the cost of surplus resource, PG&E's PCIA rate decreases as their surplus resources become more cost effective relative to market prices. This methodology results in a base case PCIA forecast after 2020 that increases by an average of 2 percent per year over the 10-year period. This resultant PCIA forecast is consistent with PCIA rate forecasts contained in other CCA feasibility studies.

Franchise Fee Surcharge

The franchise fee is a surcharge that PG&E pays cities and counties for the right to use public streets to provide utility services. The franchise fee is a revenue source for municipalities imposed on privately owned utilities. The franchise fee is a "rental" or "toll" for the use of a municipality's streets and poles, as well as for permission to provide service in their jurisdiction. "The Franchise Act establishes that a franchise fee of 2 percent of the franchisees gross annual receipts arising

[26] See D.-6-07-030 as modified by D. 11-12-018.

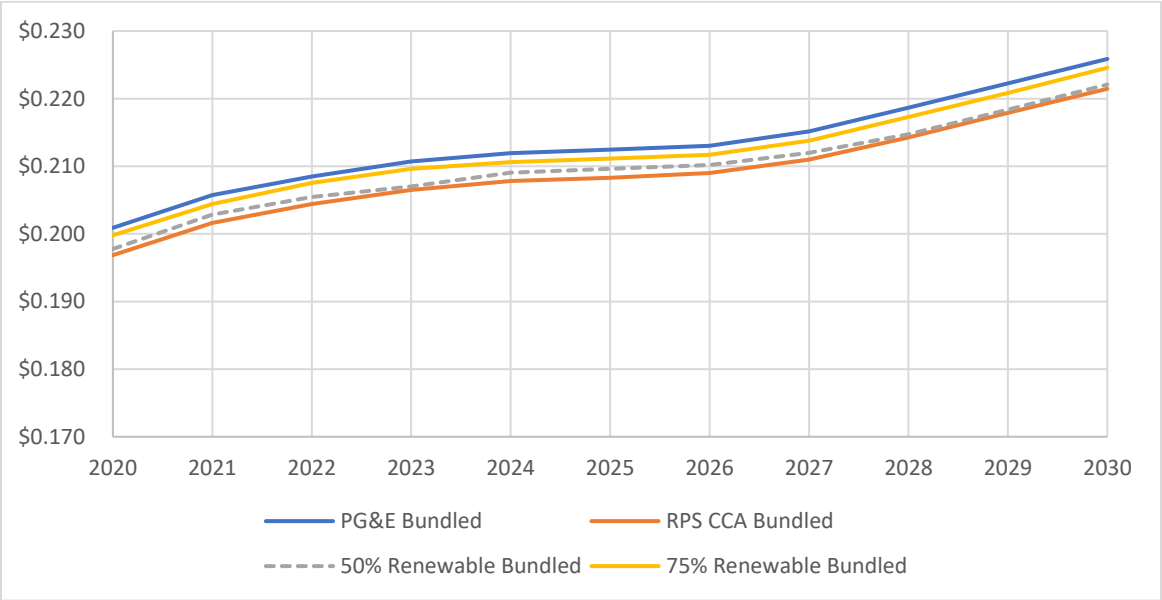
from the use, operation, or possession of the franchise …. within the city limits[27]" must be paid to the municipality.

PG&E collects the franchise fee surcharge and passes it to cities and counties. This tax is part of PG&E's current rates and is therefore passed on to the CCA customers as a non-bypassable charge called the Franchise Fee Surcharge. PG&E will continue to collect the Franchise Fee Surcharge for both generation and distribution services and pay the owed revenue to the cities and counties, regardless of the power supplier. The franchise fee is not forecast to change during the Plan horizon. The formation of a CCA does not affect the amount of franchise fee paid to cities and counties, and also does not require the negotiation of a new franchise fee agreement.

Retail Rate Comparison

Based on the CCA's projected power supply costs, PCIA and operating costs, and PG&E's power supply and delivery costs, forecasts of CCA and PG&E total rates have been developed. These rates are illustrated below on Exhibits 23A and 23B. Exhibit 23-A shows the minimum rates that the CCA would be able to support while still covering expenses and generating 90-days of reserves. Exhibit 23-B shows the expected rates if the 50 percent renewable product rate is targeted to 2% of the PG&E bundled rate, and the 75 percent renewable product rate is targeted to 0.5% of the PG&E bundled rate.

Exhibit 23-A
Minimum Average Total Retail Rate Comparison – 4 Participant CCA



[27] The California Municipal Law Handbook. 2002 Edition

Exhibit 23-B
Average Total Retail Rate Comparison – With Savings Targets – 4 Participant CCA

The CCA RPS residential rate with an equal amount of renewable power to that projected for PG&E can be at most approximately 4 percent lower initially, then can range from 3 to 4.4 percent lower, as can be seen in Exhibit 24. The CCA residential rate with 50 percent renewable power can be up to 4 percent lower initially then can range from 2.9 to 3.9 percent lower, while the rate with 75 percent renewable can be 0.5 percent lower initially then can range from 0.9 to 1.4 percent lower. The rates calculated under this Plan are for comparison to PG&E rates only. Under formal operations, the CCA policymakers will determine the actual rates to be offered to its customers. For the purpose of this Plan, a 2% bill savings target is assumed for the RPS case, 1.5% bill savings in the 50 percent renewables case, and a 0.5% bill savings target is assumed for the 75 percent renewable product.

Based on these estimated CCA discounts off the comparable PG&E rate, Exhibit 24 provides a comparison of the indicative bundled rates for CCA's products based on the projected 2022 PG&E rate. These indicative rates are calculated as a percentage off PG&E's bundled rates.

Exhibit 24 Indicative Rate Comparison in $/kWh				
Rate Class	**2022 PG&E Bundled Rate***	**Indicative Butte RPS Bundled Rate**	**Indicative Butte 50% Renewable Bundled Rate**	**Indicative 75% Renewable Bundled Rate**
Residential	0.2033	0.2007	0.2019	0.2035
Small Commercial	0.2436	0.2440	0.2453	0.2469
Medium Commercial	0.2151	0.2122	0.2135	0.2152
Large Commercial	0.1807	0.1676	0.1688	0.1703
Street Lights	0.2184	0.2002	0.2011	0.2023
Agriculture	0.2405	0.2407	0.2418	0.2432
Industrial	0.1543	0.1395	0.1406	0.1420
Total	**0.2057**	**0.2016**	**0.2029**	**0.2044**
Initial Rate Savings in 2022 from PG&E Bundled Rate		**2.00%**	**1.50%**	**0.50%**
Maximum Rate Savings After Fully Operational		**3.9-4.4%**	**2.9-3.9%**	**0.9-1.4%**

*PG&E bundled average rate projected based on PG&E's 2018 Rates.

A financial pro forma in support of these rates can be found in Appendix B.

Exhibit 24 provides the rate comparison of CCA projected rates to PG&E's estimated bundled rate projected forward to 2020 from the 2018 ERRA filing. Exhibit 25 provides the comparison for a residential customer of CCA projected rates to PG&E's bundled rate and PG&E's rate offerings for additional renewable power. For 2018, PG&E charges $0.02002 per kwh for each additional renewable kwh requested by a residential customer.

Exhibit 25 Residential Rate Comparison for 2022 – 4 Participants			
	PG&E Indicative Rate	**Butte County CCA Indicative Rate**	**Percent Difference**
50% Renewable	0.21336	0.20193	5.4%
75% Renewable	0.21836	0.20350	6.8%

Exhibit 25 shows that the CCA's portfolios with additional renewable resources can provide savings to residential customers compared to PG&E's additional renewable rate offerings.

Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

The amount of renewable power in PG&E's power supply portfolio is 33 percent[28] and will rise to 37 percent by 2020 and 50 percent by 2030.[29] At this time, PG&E's resource mix is 79 percent GHG-free due to power supply from large hydro, nuclear, and renewable resources. Most likely PG&E will reduce market purchases (i.e., natural gas fired generation) as CCA customers leave PG&E service.

As outlined in the Resource Portfolio section above, the RPS Portfolio scenario assumed that the CCA's resource portfolio is 80 percent GHG-free in all years. In the 50% Renewables Portfolio and the 75% Renewables Portfolio it is assumed that the CCA's resource portfolio is 80 percent GHG-free in 2019 and 2020 and that the GHG-free resources increase by 1.5 percent each year after 2020 until 2030 when GHG-free resources are 95 percent. The remaining non-GHG-free energy will generate amounts of carbon dioxide as outlined in Exhibit 26. The average portfolio GHG-free percentage over the full study period (88%) was used for this calculation, to account for the higher GHG-free levels in later years in the 50% and 75% Renewables scenarios. Average annual emissions from the three portfolios for 2020-2030 are presented below. In each case, it was assumed that the full CCA load (1,200 GWH) was in each portfolio. In other words, if, for example, the CCA decides to offer both RPS and 50% Renewables products and some proportion of customers fall into each product bucket, the emissions would fall somewhere between 53,887 and 89,812 metric tons of CO_2e/year.

Exhibit 26
Comparison of Average Annual GHG Emissions from Electricity, by Resource Portfolio (2020-2030)

	RPS 80% GHG-free	50% Renewable 88% GHG-free	75% Renewable 88% GHG-free
CO2 Emissions (Metric tons of CO_2e/year)[30]	89,812	53,887	53,887

Local Resources/Behind the Meter Butte County CCA Programs

The CCA will have the option to invest in a range of programs to expand renewable energy use and enhance economic development in the County. Increased renewable energy use can be accomplished by supporting customers wishing to own small renewable generation (net energy metering), purchasing from small local for-profit renewable generators (feed-in tariffs), purchasing renewable resources directly, or supporting electric vehicle use. Each of these programs also yields economic development benefits by spending locally and saving local

[28]https://www.pge.com/pge_global/local/assets/data/en-us/your-account/your-bill/understand-your-bill/bill-inserts/2017/november/power-content.pdf

[29] http://www.cpuc.ca.gov/RPS_Procurement_Rules_33/, http://www.energy.ca.gov/portfolio/16-RPS-01/

[30] Methodology follows the "GHG Accounting Methodology for LSE Portfolio Development in the IRP 2017-18 Cycle" as proposed by the CPUC staff

customers money. In addition, economic development can be accomplished through additional support for low-income customers or extra support for new or growing businesses. The following sections discuss these programs.

Economic Development

Economic development is another priority for many of the CCAs in California. Local economic development is bolstered through retail rate savings as well as through the locally focused programs offered by the CCAs.

One such program is a special economic development rate to encourage manufacturers or other types of large commercial and industrial industries to site new or expanded operations within the CCA service territory. Additional loads would then bring jobs and tax revenue. The type of new load may also have an impact on average power supply costs. New loads that improve the system load factor will reduce power supply costs and these savings can be passed through to the new large load customer in the form of lower rates. Finally, new large loads may have the flexibility to participate in demand response programs further reducing the average cost of power supply.

Net Energy Metering (NEM)

The CCA should establish a Net Energy Metering (NEM) program for qualified customers in their service territory to encourage wider use of distributed energy resources (DER) such as rooftop solar. NEM programs allow energy customers who generate some or all of their own power to sell excess generation to the grid and benefit from a credit for those sales when they become a NEM consumer.

PG&E currently offers a NEM program in which customers receive an annual "true-up" statement at the end of every 12-month billing cycle. This allows customers to balance credit earned in summer months with charges accrued in the winter. Customers earn power credits at the market rate at the time of generation, between $0.03 and $0.04 per kilowatt-hour (kWh)[31], though they are not paid for excess generation. Credits unused at the end of each year expire. This policy therefore incentivizes customers to limit the size of their generation system given as excess generation will not provide a return.

All of the CCAs currently operating in California also offer NEM programs, and three of the most recently operational CCAs have offered them at the launch of service[32]. These programs are across the board more favorable for NEM customers than the IOU's. These CCAs allow for higher

[31]https://www.pge.com/en_US/residential/solar-and-vehicles/green-energy-incentives/solar-and-renewable-metering-and-billing/how-to-read-your-bill/how-to-read-your-bill.page
[32]https://pioneercommunityenergy.ca.gov/home/nem-solar/, https://www.poweredbyprime.org/faq, http://www.applevalley.org/home/showdocument?id=18607

reimbursement rates, roll-over of earned credits as well as cashing out on credits earned over $100.

All of these CCA-managed NEM programs offer greater incentives for customers in their service area to invest in more and larger DER. This has the benefit of increasing the supply of renewable resources available to these CCAs as well as encouraging high participation rates among current and potential NEM customers. Butte County CCA has the option to implement a similar NEM program.

Feed-in Tariffs

Feed-in tariffs (FIT) offer terms by which electric service providers such as IOUs and CCAs purchase power from small-scale renewable electricity projects within their service territory. In contrast with NEM programs, which typically target owners of homes and small businesses who wish to install a rooftop photovoltaic (PV) system, FIT programs target owners of larger generation projects, in the range of 0.5-3 MW. These could be larger rooftop photovoltaic (PV) systems located at industrial sites or ground-mounted shade in parking lots.

PG&E currently offers its Renewable Feed-in-Tariff (ReMAT), available to renewable generation projects from 1.5 to 3 MW, with prices around $89 per Megawatt hour (MWh).[33] Sonoma Clean Power (SCP) offers its own FIT program for generating facilities under 1 MW at a flat rate of $95/MWh.[34] Marin Clean Energy (MCE) also offers a FIT program for generating facilitates under 1 MW with prices ranging from $90 to $137.66/MWh.[35]

In developing a FIT program of its own, the Participants' CCA would incentivize customers in their service area to develop local renewable resources and improve participation among this customer class as well. If the FIT resources are certified, then the CCA may be able to use the FIT program as a long-term RPS procurement strategy.

Local Generation Resources Development

A final option to drive growth in local renewable generation resources within the CCA service area is for the CCA itself to build or acquire generation resources. MCE currently has 10.5 MW of CCA-owned local solar PV projects under development and is planning to develop or purchase locally constructed, utility scale renewable generating capacity with a potential of up to 25 MW total by 2021.[36] This model of CCA-owned resources provides CCAs with a guaranteed renewable power source as well as local economic stimulus.

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[33]https://www.pge.com/en_US/for-our-business-partners/floating-pages/remat-feed-in-tariff/remat-feed-in-tariff.page
[34]http://sonomacleanpower.org/profit/#summary
[35]https://www.mcecleanenergy.org/wp-content/uploads/FIT_Tariff_5.15_FINAL.pdf
[36]https://www.mcecleanenergy.org/wp-content/uploads/2017/11/MCE-2018-Integrated-Resource-Plan-FINAL-2017.11.02.pdf

Electric Vehicle (EV) Programs and Charging Stations

Encouraging electric vehicle use can both increase load serving entity ("LSE") load and simultaneously generate environmental benefits. Many LSEs offer special rates for electric vehicle charging. PG&E offers two non-tiered, time-of-use (TOU) plans: EV-A combines the loads of vehicle charging with the load of the residence. EV-B customers install a separate meter explicitly for vehicle charging.[37] TOU rates encourage vehicle charging at times when energy is cheapest or system load is lowest. MCE offers a similar program for their customers with lower rates.[38]

In addition to targeted rate programs, CCAs can encourage electric vehicle use by investing in local electric vehicle charging stations. Silicon Valley Power (SVP) opened the largest public electric vehicle charging center in the State in April 2016. The facility features 48 Level 2 chargers and one DC Fast Charger[39]. SCP also provided qualified customers with incentives to purchase EVs in 2016 and continued the program in 2017.[40] The Participants' CCA could invest in similar projects to promote electric vehicle use within its service area.

Low Income Programs

PG&E offers assistance to low-income customers on both one-time and long-term bases. PG&E offers one-time energy credits up to $300 through their Relief for Energy Assistance through Community Help (REACH) program.

For customers in need of more sustained assistance, PG&E offers rates that are 20 percent or lower for qualifying households under the California Alternate Rate Energy (CARE)[41] program. The CARE program is mandatory for IOUs per California Public Utilities Code 739.1. The program is set up for electric corporations that have 100,000 or more customer accounts to provide 30-35 percent discount on electric utility bills on households that are at or below 200 percent of the federal poverty line. Funding for CARE is collected on an equal cents/kWh basis from all customer classes except street lighting. This program, like other PG&E programs, would continue to be available to CCA customers either through PG&E or the CCA.

In addition, the Family Electric Rate Assistance (FERA) Program can provide a monthly discount on electric bills. This program is designed for income-qualified households of three or more persons. Finally, the California Department of Community Services and Development (CSD)

[37] http://www.pge.com/myhome/environment/whatyoucando/electricdrivevehicles/rateoptions/
[38] https://www.mcecleanenergy.org/electric-vehicles/
[39] http://www.siliconvalleypower.com/Home/Components/News/News/5036/2065
[40] https://sonomacleanpower.org/sonoma-clean-power-launches-ev-incentive-program/

[41]https://www.pge.com/en_US/residential/save-energy-money/help-paying-your-bill/payment-assistance-overview/payment-assistance-overview.page

oversees a federal program, Low-income Home Energy Assistance Program (LIHEAP), which offers help for heating or cooling homes and help for weatherproofing homes.

At present, most California CCAs simply match their incumbent IOU's low-income programs, as in the case of MCE and SCP. It is important to note that PG&E is the only IOU in the State to charge the PCIA to CARE customers. It is assumed that the Participants' CCA will continue to provide the same support to low-income customers as does PG&E.

Economic Impacts in the Community

The analyses contained in this Plan of forming a CCA in Butte County has focused only on the direct effects of this formation. However, in addition to direct effects, indirect microeconomic effects are also expected.

The indirect effects of creating a CCA include the effects of increased commerce, and disposable income. Within this Plan, an input-output- (IO) analysis is undertaken to analyze these indirect effects. The IO model turns on the assumption that forming a CCA will lead to lower energy rates for their customers. Three types of impacts are analyzed in the IO model. These are described below.

Local Investment – The CCA may choose to implement programs to incentivize investments in local distributed energy resources (DER). Participants in the CCA may pursue local clean DER. These resources can be behind the meter or community projects where several customers participate in a centrally located project (e.g. "community solar"). This demand for local renewable resources will lead to an increase in the manufacturing and installation of DER, and lead to an increase in employment in the related manufacturing and construction sectors.

Increased Disposable Income – Establishing a CCA will lead to reduced customer rates for energy, more disposable income for individuals, and greater revenues for businesses. These cost savings would then lead to more investment by individuals and businesses for personal or business purposes. This increase in spending will then lead to increased employment for multiple sectors such as retail, construction, and manufacturing.

Environmental and Health Impacts – With the creation of a CCA, other non-commerce indirect effects will occur. These may be environmental, such as improved air quality or improved human health due to the CCA potentially utilizing more renewable energy sources versus continuing use of traditional energy sources which may have a greater GHG footprint. While a change in GHG emissions is not modeled directly in economic development models used in this Plan, the reduction of these GHGs may be captured in indirect effects projected by the models.

Input-Output Modeling (IO modeling)

County-wide electric rate savings and growth in manufacturing jobs and other energy intensive industries are expected to spur economic development impacts. Exhibit 28 shows the effect $5 million in rate savings could have on the County economy as estimated in the Butte County IMPLAN model. The $5 million rate savings represents the minimum bill savings per year once the CCA has achieved full operation and all 4 Participants are included. The IMPLAN model is an input-output (IO) model that estimates impacts to an economy due to a change to various inputs such as industry income, supply costs, or changes to labor and household income. Both positive and negative impacts can be measured using IO modeling. IO modeling produces results broken down into several categories. Each of these is described below:

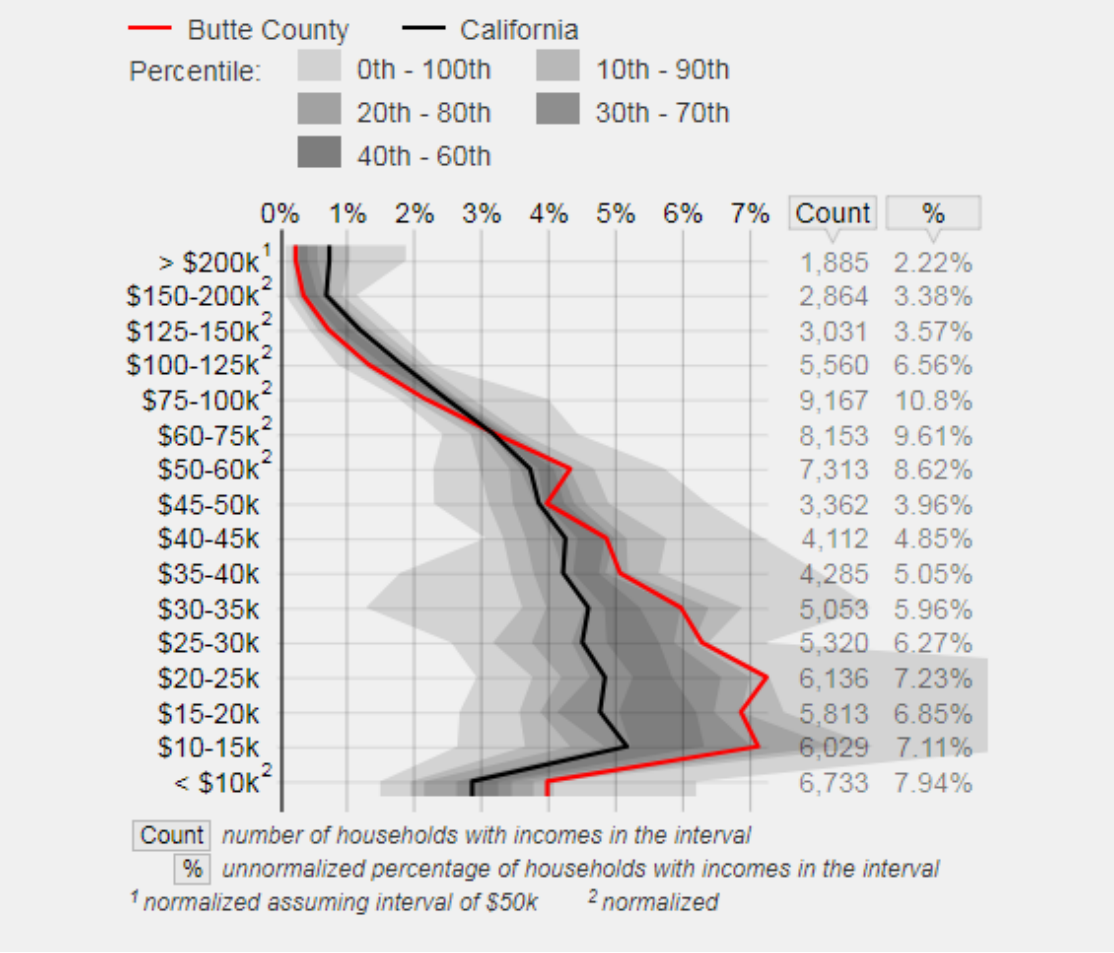
- **Direct Effects –** Increased purchases of inputs used to produce final goods and services purchased by residents. Direct effects are the input values in an IO model, or first round effects.
- **Indirect Effects –** Value of inputs used by firms affected by direct effects (inputs). Economic activity that supports direct effects.
- **Induced Effects –** Results of Direct and Indirect effects (calculated using multipliers). Represents economic activity from household spending.
- **Total Effects –** Sum of Direct, Indirect, and Induced effects.
- **Total Output –** Value of all goods and services produced by industries.
- **Value Added –** Total Output less value of inputs, or the Net Benefit/Impact to an economy.
- **Employment –** Number of additional/reduced full time employment resulting from direct effects.

This Plan uses value added and employment figures to represent the total additional economic impact of the rate savings associated with forming the CCA.

The rate savings are modeled for residential, commercial, industrial, and agricultural sectors. For residential, the rate savings are modeled at different household income levels to estimate the impact on the economy from reduced bills. Household income distribution is estimated based on the income percentiles from the statistical atlas for Butte County.[42] Exhibit 27 summarizes the high-level breakdown for income distribution within the county compared with the rest of the State.

[42] Statistical Atlas. Butte County, California. Available online: https://statisticalatlas.com/county/California/Butte-County/Household-Income data from U.S. Census Bureau.

Exhibit 27
Household Income Distribution, Butte County and California[43]



The change in household income assumes that all households are impacted proportionately; however, in practice lower income households may see the most significant benefit due to their electric use. Generally, lower income families are not able to reduce their utility bills as easily through efficiency upgrades or modified behavior due to lack of disposable income. Therefore, the impacts are likely underestimated.

Non-residential impacts are estimated using the top ten industries in the County, which account for over 80% of the CCA revenue. Rate savings are allocated to each industry based on the share of revenue. This method assumes that energy use is positively correlated with industry revenue. Major agricultural activities in the County include tree nut farming, plums, rice, almonds and nursery products. Major commercial and industrial industries include government, healthcare,

[43] Normalized with respect to standard interval of $5k. Gray areas represent percentile bands from the counties in California. © OpenStreetMap contributors Available online: https://statisticalatlas.com/county/California/Butte-County/Household-Income#figure/household-income-percentiles

retail, manufacturing, construction, professional and scientific services, finance, accommodation and food services, and wholesale trade.

Exhibit 28 details the macroeconomic impacts anticipated from the 2% savings in the generation rate from after forming the CCA. The total added value for one year of rate savings is estimated at $3.6 million. Finally, the rate savings are estimated to produce an additional 42 full time jobs.

Exhibit 28
$5 Million Rate Savings Effects on the Butte County Economy

Impact Type	Employment	Labor Income	Total Value Added	Output
Direct Effect	13.9	$788,000	$1,383,000	$2,239,000
Indirect Effect	3.7	$169,000	$267,000	$489,000
Induced Effect	24	$1,024,000	$1,902,000	$3,198,000
Total Effect	41.7	$1,981,000	$3,552,000	$5,926,000

These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand. In addition, reduced inputs to production for non-residential electric customers will allow companies to invest in other areas to promote growth such as hiring new employees, additional training, upgraded equipment, etc.

DER Development Impacts

The economic impacts of DER development are estimated using the Jobs and Economic Development Impact (JEDI) model.[44] JEDI estimates the effects of DER development on construction industries and the local economy. JEDI was initially developed by the National Renewable Energy Laboratory to demonstrate the economic benefits associated with constructing and operating wind and photovoltaic systems in the United States. JEDI has since been expanded to analyze similar economic impacts for various energy sources such as biofuels, coal, concentrating solar power, geothermal, marine and hydrokinetic power, and natural gas. A primary goal of JEDI is that it is being used as a tool for system developers, renewable energy advocates, government officials, decision makers, and others to easily identify the local economic impacts associated with constructing and operating these systems on the economy, whether through direct and indirect effects.

Users input general information about a particular energy project, such as the project location, the type of system being installed, nameplate capacity, annual operations and maintenance costs, and others. JEDI has default but modifiable data regarding various aspects of each energy system type, such as equipment costs, tax parameters, and labor costs. JEDI then uses the input

[44] http://www.nrel.gov/analysis/jedi/

general information and the data, default or modified, to run calculations on the types of economic effects produced by the proposed project. This model projects direct job creation by industry, indirect job and business increases due to the project, projected operation costs, and more.

In order for JEDI to provide information, it must be populated with detailed data for the assumed DER project. Projected system data, type of solar cell, nameplate capacity (kW), and the number of systems. As an example of the macroeconomic activity caused by local DER deployment, this example assumes the installation of a 10-crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 10 MW. Exhibit 29 describes the local macroeconomic impacts of constructing a sample 10 MW local solar project in Butte County as estimated from a state-wide perspective. The economic impacts will be spread across both the County and the state.

Exhibit 29
Projected 10 MW Solar System Impacts on Butte County Economy

Description	Jobs	Earnings, $000	Output (GDP), $000
During Construction and Installation Period			
*Project Development and Onsite Labor Impacts			
Construction and Installation Labor	68.5	$4,436	
Construction and Installation Related Services	74.9	$4,001	
Subtotal	143.4	$8,438	$13,524
*Module and Supply Chain Impacts			
Manufacturing Impacts	0.0	$0	$0
Trade (Wholesale and Retail)	15.9	$885	$2,578
Finance, Insurance and Real Estate	0.0	$0	$0
Professional Services	10.8	$465	$1,382
Other Services	28.3	$3,010	$8,473
Other Sectors	63.4	$2,131	$3,886
Subtotal	118.4	$6,491	$16,317
Induced Impacts	65.3	$2,613	$7,818
Total Impacts	**327.1**	**$17,542**	**$37,660**
During Operating Years			
*Onsite Labor Impacts			
PV Project Labor Only	1.8	$111	$111
*Local Revenue and Supply Chain Impacts	0.5	$29	$92
*Induced Impacts	0.4	$15	$44
Total Impacts	**2.7**	**$155**	**$247**

Exhibit 29 shows the construction and ongoing effects of building a 10 MW solar power system. It is projected that roughly 327 jobs will be created during construction and installation. Of this

total, about 143 jobs will be directly involved in construction and installation while roughly 118 jobs will be indirectly involved with the building of the project. Induced impacts of the construction and installation will create approximately 65 jobs. These induced effects may include anything from increased employment in restaurants, retail, education, and others. Overall, the building of this one solar project is projected to create $17.5 million in earnings and $38 million in output (GDP) in the local economy along with 327 jobs during construction and 3 full-time jobs ongoing. Again, these effects will be shared between the county and the State.

Sensitivity and Risk Analysis

The economic analysis provides a base case scenario for forming a CCA. This base case is predicated on numerous assumptions and estimates that influence the overall results. This section of the Plan will provide the range of impacts that could result from changes in the most significant variables for the portfolios described in the Power Supply Strategy and Cost of Service sections of this Plan. In addition, this section will address uncertainties that should be addressed and mitigated to the maximum extent possible.

First, an overview of risk and uncertainties and their relative severity are examined (Exhibit 30), followed by discussion of each risk factor. In Exhibit 30, the risks are analyzed qualitatively based on the likelihood of a negative outcome for CCAs as well as the perceived severity of a negative outcome. Next, the uncertainties and risks are further ranked qualitatively from the perspective of the proposed CCA formed by the Participants (Potential to "break" Butte County CCA). All qualitative ranking is subjective based on recent California experience. For variables where risk is quantified, key assumptions are discussed and a reasonable range of outcomes is established. The range in variable assumptions is meant to reflect probable futures, but do not demonstrate the full scope of possible outcomes. The CCA's rate impacts are estimated using a range of likely outcomes and presented in a scenario analysis.

Exhibit 30 Comparison of Risks, Mitigation Strategies and Risk Severity							
	Risk	**Description**	**Problem**	**Mitigation Strategy**	**Likelihood of Problem**	**Severity of Problem**	**Potential to "Break" Butte County CCA**
1	PG&E Rates and Surcharges	PG&E's generation rates decrease or its non-bypassable charges increase	• Butte County CCA rates exceed PG&E • Increased customer opt-out rate	• Establish Rate Stabilization Fund • Invest in a balanced portfolio to remain agile in power market •Emphasize the value of programs, local control, and environmental impact in marketing	High – most operating CCAs in California have undergone short periods of rate competition from the incumbent IOU.	Medium - CCAs have always been able to buffer rate impacts using financial reserves, then adjust power supply to regain rate advantage.	Low – only in the event of very poor contract management by Butte County CCA and unprecedented changes in IOU rates.
2	Regulatory Risks	Energy policy is enacted that compromises CCA competitiveness or independence	• New costs incurred • Reduced authority	• Coordination with CCA community on regulatory involvement • Hire lobbyists and regulatory representatives	Low – existing regulatory precedent makes the likelihood of state policies that severely disadvantage CCAs low.	High – a worst case scenario regulatory legislative decision limiting CCA autonomy or enforcing additional costs could hinder CCA viability.	Low – energy policy severe enough to make Butte County CCA infeasible is very unlikely.
3	Power Supply Costs	Power prices increase at crucial time for Butte County CCA	• Butte County CCA rates exceed PG&E • Increased customer opt-out rate	• Long-term contracts • Draw on Butte County CCA reserves to stabilize rates through price spike	Low – market prices are unlikely to spike enough to make Butte County CCA financially infeasible prior to CCA launch. From that point on, the CCA can limit its exposure through contract selection.	Medium – a poorly timed price spike combined with poor power supply contract management could require Butte County CCA to dig into reserves or delay launch.	Very low
4	PG&E RPS Share	PG&E's RPS or GHG-free power portfolio grows to match or exceed Butte County CCAs	Increased customer opt-out rate	• Increase renewable power portfolio • Emphasize rates and local programs in marketing	Medium – PG&E's power portfolio is dynamic and could change rapidly as a result of other CCA departures.	Low – CCA will have capability to increase renewable energy purchases to match or exceed PG&E if the event occurs. In addition, Butte County CCA will promote other benefits of its service to customers.	Very Low – CCA is highly likely to respond effectively if this occurs.

5	Availability of RPS/GHG-Free Power	Unexpectedly high market demand or loss of supply of renewable resources	• Butte County CCA unable to provide target power products	• Shift emphasis to GHG-free or RPS resources depending on availability • Secure long-term contracts • Invest in local renewable resources	Low – power procurement providers report a plethora of RPS and GHG-free bids available on the market.	Medium – if Butte County CCA were unexpectedly unable to procure enough RPS or GHG-free power, it could emphasize other program strengths to retain customers until new resources came online.	Very Low – negligible chance of occurring.
6	Financial Risks	Butte County CCA is unable to acquire desired financing or credit	• Slower or delayed program launch • Unable to build generation projects	• Adopt gradual program roll-out • Establish Rate Stabilization Fund • Minimize overhead costs	Low – CCAs have become sufficiently established in California that financing is almost certainly available.	Medium – in the event Butte County CCA is limited in financing options, it can adopt a more conservative program design and gradual roll-out.	Very Low
7	Loads and Customer Participation	Unprecedented opt-out rate reduces competitiveness	• Excess power contracts • Poor margins	• Increase marketing • Reduce overhead • Expand to new customer markets • Consider merging with existing CCA	Low – as CCAs have become more common in California, and CCA marketing firms more experienced, opt-out rates have gone lower and lower.	Low – Butte County CCA will have numerous viable options in the event they suffer unexpectedly low participation.	Very Low

PG&E Rates and Surcharges

Sensitivity analyses were conducted for two components of PG&E rates. Assumptions are described below. The delivery rates are paid by both CCA and PG&E bundled customers. As such, their increase or decrease impacts all customers equally.

Generation Rate

PG&E generation rates are projected to increase on average by 0.3 percent per year over the next 10 years based on the projected market prices, PG&E's resource mix and renewable resource growth rates. To explore the impact in the case that PG&E's generation rate changes significantly relative to the CCA's generation cost, PG&E's generation cost was modeled in the high and low case by incorporating higher and lower generation growth rates. This results in PG&E's power supply average annual growth rate in the high case of 2.3 percent and in the low case of -0.7 percent.

PCIA

When legislation was introduced to allow the formation of CCAs, it was recognized that the IOUs currently serving the potential CCA customers may face stranded generation costs. The PCIA methodology was established by the CPUC as a means for IOUs to recover those stranded costs. The PCIA faces several issues, however, including the source and transparency of data used for the calculation and the fact that the PCIA level is highly variable causing a significant amount of uncertainty.

A PCIA proceeding is underway, and the IOUs and CCA community have presented alternative calculation methods for use going forward. The proposed methodologies revise the previously proposed Portfolio Allocation Mechanism (PAM) to divide the cost into two resource accounts: The Green Allocation Mechanism (GAM) and the Portfolio Monetization Mechanism (PMM). In both the PAM and the revised proposal (GAM and PMM), the CCA would be allocated RECs and RA credits based on load and peak load share of the CCA, respectively. While the fee charged to customers may increase, some of the increase would be offset by the REC and RA credits. Under these scenarios, the CCA is essentially purchasing RECs and RA resources from the IOUs. A decision from the CPUC regarding the calculation method is expected by the end of the summer 2018.

The level of the PCIA, or other non-bypassable charge that will potentially replace the PCIA, will impact the cost competitiveness of the Participants' CCA. In order to be cost-effective, the CCA's power supply costs plus PCIA and other surcharges must be lower than PG&E's generation rates. Many factors influence the PCIA but primarily the PCIA is determined by the cost of power contracts and the cost to PG&E of the departing load. Uncertainties surrounding the PCIA include methodology assumptions unique to PG&E as well as to what degree previously acquired power contracts can be retired. The potential for the PCIA to increase sharply occurs when PG&E must

sell previously contracted power at times when wholesale power prices are much lower. The PCIA also has potential to decrease since it reflects PG&E's own resources and signed contracts obtained prior to load departure; once the contracts expire, the related PCIA will disappear. Therefore, over time, the PCIA will vary, but it is expected that it will decline as market prices increase and grandfathered contracts expire.

Forecasting the PCIA is difficult since key inputs are heavily redacted from the rate filings and regulatory changes can significantly impact the PCIA. The uncertainty associated with forecast PCIA rates is modeled considering historic PCIA increases as well as the methodology used for the PCIA calculation where contracts are retired over time.

In the high case, it was assumed that the PCIA would increase by 73 percent in 2019 and remain at that level. The high case assumes that the proposed GAM/PMM costs go into effect, where market prices remain low and that PG&E must sell newly acquired power contracts at a loss. However, the RA and REC credits that the CCA would receive in conjunction with the GAM/PAM mechanism have not been included. This creates a very conservative case, where the increased cost to customers is modeled without the offsetting impact of the credits. For the low case, it was assumed that the PCIA decreases by 2 percent per year due to the expiration of contracts and/or increased market prices.

Regulatory Risks

There are numerous factors that could impact PG&E's rates in addition to the market price impacts described above. Regulatory changes, plant or technology retirements or additions, and the long-term impact of the Diablo Canyon closure all can impact PG&E's rates in the future. Regulatory issues continue to arise that may impact the competitiveness of the Participants' CCA. The impact of these factors is difficult to assess and model quantitatively. However, California's operating CCAs have worked hard to address any potentially detrimental changes through effective lobbying, and technical support in Sacramento and San Francisco.

New legislation can also impact the Participants' CCA. For example, new legislation that recently affected CCAs is SB 350. The CCA-specific changes reflected in SB 350 are generally positive, providing for ongoing autonomy with regard to resource planning and procurement. CCAs must be aware, however, of this legislation's long-term contracting requirement associated with renewable energy procurement.

Regulatory risks also include the potential for utility generation costs to be shifted to non-bypassable and delivery charges. The existing PCIA methodology is currently being evaluated and may be replaced in the future with a methodology that increases costs to customers, while transferring REC and RA benefits to the CCA.

In addition, there is a risk that additional capacity resource costs are pushed onto CCAs via the Cost Allocation Mechanism (CAM). The CCA will need to continually monitor and lobby at the Federal, State and local levels to ensure fair and equitable treatment related to CCA charges.

Power Supply Costs

Natural gas-fired generation is predominantly used as the marginal resource within the State's dispatch order. Therefore, wholesale market prices are driven largely by natural gas prices. In addition, the CCA's power supply mix has been modeled according to different levels of renewable energy. Renewable energy costs are forecast for the base case; however, several factors could influence future renewable energy costs including locational factors for new facilities, transmission costs, technology advancements, changes in renewable energy incentives, or changes in California or neighboring state RPS.

Since resource costs are based on forecast wholesale market and renewable market prices, it is prudent to look at the sensitivity of the 20-year levelized cost calculation to fluctuations in these projections. Exhibit 31 below shows a summary of low, base, and high resource costs.

Exhibit 31
Low, Base and High 20-year Levelized Resource Costs ($/MWh)

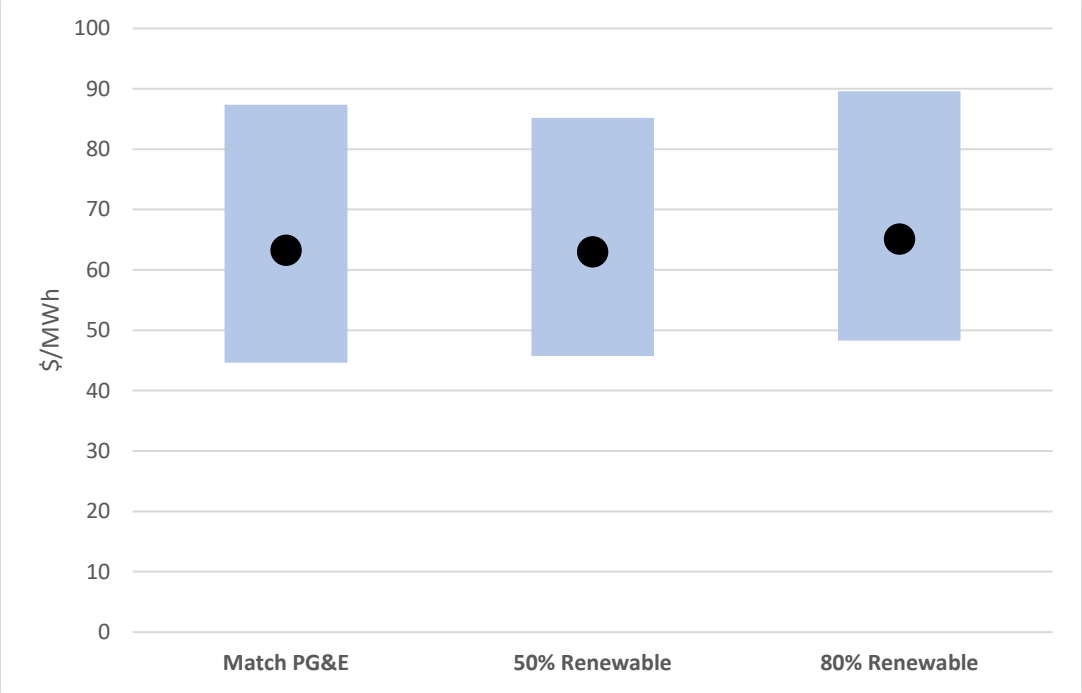
Case	Market PPA (1)	Portfolio 1 Match PG&E Renewables	Portfolio 2 50% Renewables	Portfolio 3 75% Renewables	Local Renewables
Low Case	28.2	44.6	63.2	87.4	45
Base Case	53.6	46.8	64.5	90.2	65
High Case	77.0	48.3	65.1	89.6	85

(1) Excludes GHG-free premiums included in a portion of market PPA purchases costs in order to achieve the GHG-free purchase targets. Premiums escalate from $3.50/MWh in 2020 to $7/MWh in 2039. The 20-year levelized cost of the premium is $4.8/MWh.

Portfolios 1 through 3 are modeled based on low, base and high forecasts for wholesale market and renewable costs. The base case renewable energy costs are based on the cost of PPAs currently being executed in the region. The low case renewable energy costs are based on an assumption that the costs of renewable generating projects will, as expected, continue to decline and the CCA will, over time, layer in PPAs sourced to the lower cost renewable resources that will be developed over the next five to ten years. The high case renewable energy costs are based on an assumption that the CCA is not able to secure PPAs sourced to relatively new and lower cost renewable resources but, rather, signs PPAs sourced to older renewable resources with higher costs. The renewable costs in this case reflect the costs of renewable resources that were developed three to five years or more ago.

The 20-year levelized costs of each portfolio has been calculated using the range of resource costs shown above. The base case costs are depicted by the black dots in Exhibit 32.

Exhibit 32
Sensitivity of Portfolio 20-year Levelized Costs



Portfolio 3, which relies on the most renewable energy purchases to serve retail load, has the highest projected costs that range from a low of $50/MWh to a high of $89/MWh. The likelihood of renewable project costs increasing to the point that 20-year levelized costs of renewable purchases is near $84/MWh is low (the high case under Portfolio 1). All signs point to decreases in solar equipment costs on a $/watt basis. There have been significant decreases in solar costs over the past few years.

The potential for market PPA prices to increase to the high case of near $77/MWh is much greater. Wholesale market prices are dependent on many factors, the most notable of which is natural gas price. Natural gas prices are at historic lows and wholesale market prices have followed. However, natural gas prices are subject to a variety of local, national and international forces that could alter the current marketplace. For one, increased regulation of the natural gas industry with respect to the deployment of fracking technology could cause decreases in natural gas supplies and commensurate increases in natural gas prices. If natural gas prices increased, it is highly likely that electric wholesale market prices would also increase. Increased costs associated with carbon taxes and/or carbon cap and trade programs could also cause upward pressure on wholesale market prices.

When evaluating risks, it is important to note that power supply costs are approximately 60 percent of the total costs, PG&E non-by-passable charges account for 25 percent and operating costs account for 15 percent of total CCA revenue requirement.

PG&E RPS Portfolio

There are several factors that may impact the share of renewable energy in PG&E's portfolio over the next decade. First, PG&E proposed plans to close their Diablo Canyon Nuclear Power Plant, which were approved by the CPUC in January 2018. The decision reduces PG&E's total generation, increasing the effective share of renewables from current contracts. Any investments in renewables to cover some portion of Diablo plant's generating capacity would compound this trend. Future procurement plans will be evaluated with the Integrated Resource Planning proceeding.[45]

Second, customers departing PG&E for CCA service throughout PG&E territory will have the effect of shrinking PG&E's load, thereby increasing the share of renewables made up by PG&E's current RPS contracts. Finally, PG&E could begin striving to compete with CCAs in terms of the environmental impact of its power portfolio. In combination, these forces could drive up the share of renewable energy in PG&E's power mix to match or exceed the CCA's planned power mix. Left unchecked, these trends could compromise the CCA's advantage over PG&E in its environmental impact.

However, there are several factors that mitigate this risk. First, PG&E's current renewable power contracts are grossly above current market price, as evidenced by the current high PCIA rates. As these current contracts grow to represent a larger share of PG&E's portfolio, they will simultaneously become less cost competitive. Second, replacing the power from the Diablo Canyon Nuclear Power Plant represents a risk to PG&E as well as the CCA. PG&E's track record for acquiring well-priced renewable contracts is poor, so future procurement plans may not increase their competitiveness either. Finally, the CCA will have the option to acquire more renewable energy in response to changes in PG&E's portfolio.

Availability of Renewable and GHG-Free Resources

Often one of the goals of a CCA is to offer a power product to its customers that is cleaner than that provided by PG&E. As renewable options, the 50 percent and 75 percent renewable portfolios developed for this Plan include more renewable resources while matching or exceeding PG&E's share of GHG resources which, depending on the amount of annual hydro generation, is in the 60 to 70 percent range.

The primary risk associated with this strategy is lack of sufficient renewable resources at prices that will keep the CCA competitive with PG&E. The current market has sufficient renewable resources available. Utilities that submit requests for renewable power supply receive bids that far exceed the requested amounts at prices that are very competitive. As RPS requirements and the share of renewable resources in CCA portfolios are increasing, competition for renewable

[45] CPUC Decision 18-01-022 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M205/K423/205423920.PDF

resources could increase. However, it is important to note that the total load has not changed because customers shift to a CCA, the renewable resource timeline may just have accelerated until targets have been reached. Increased competition will result in increased prices once supply cannot meet the demand, resulting in increased development of renewable resources. In addition, the CCAs will have the opportunity to aid in the development of renewable resources by fostering local resource development.

Financial Risks

Starting a new venture carries financial risks that will have to be considered before proceeding with a CCA. Depending on the organization structure, a third-party may take on the financial obligations of the CCA. These include establishing start-up financing, working capital funding such as lines of credit, and entering into contracts with suppliers and consultants. Other Cities and Counties have protected their General Funds by establishing JPAs or lockbox arrangements with vendors.

However, the Participants' CCA can manage many of the financial risks associated with the uncertainty surrounding a CCA start-up. While the goal is to provide clean power competitively with PG&E, the most important consideration to the third-party financer is that the CCA can increase rates if needed to ensure sufficient revenues are collected to meet costs. In addition, the CCA can plan carefully by minimizing staff initially and only growing as fast as the size of the CCA can support, thus minimizing the fixed costs of operating the CCA.

The Participants' CCA will need to manage the financial risk associated with power supply costs by managing power market and load exposure by prudent hedging and power portfolio management. In addition, the establishment of rate stabilization reserves and sufficient working capital can mitigate financial risks to the third-party financer and to customers. The success of existing CCAs in managing the financial challenges of a CCA start-up and setting rates that are competitive with PG&E can be a valuable guide for the Participants' CCA.

Loads and Customer Participation Rates

The Plan bases the load forecasts on expected load growth, load profiles, and participation rates. In order to evaluate the potential impact of varying loads, low, medium, and high load forecasts have been developed for the sensitivity analysis.

Another assumption that can impact the costs of the CCA is the overall CCA customer participation rates. This Plan uses a conservative participation rate of 95 percent for residential customers and 85 percent for non-residential customers as its base case. A higher participation rate, such as has been experienced by all of California's operating CCAs to date, will increase energy sales relative to the base case and decrease the fixed costs paid by each customer. On the other hand, a reduced participation rate will increase the fixed costs to the CCA participants.

Sensitivity to changes in projected loads has been tested for the high and low load forecast scenarios. For the sensitivity analysis, the high case assumes an additional 5 percent participation rate for non-residential customers, while the low case assumes the participation rate is reduced by 10 percent for all customers. The low case assumes a 0 percent growth in energy and customers after 2019, while the high scenario assumes a 1 percent growth in energy and customers.

The experience of existing CCAs suggest that only a small number of customers opt-out. Once the CCA is operating, the number of customers switching back to the incumbent IOU have also been very low. In order to mitigate the potential switching of customers, it will be important for Butte County CCA to implement prudent power supply strategies to address potential load swings from changes in participation and weather uncertainty, plus establish a rate stabilization fund. Keeping rates low as well as providing excellent customer service will lead to strong customer retention.

Lastly, a jurisdiction participation case was developed to present the impacts of designing a CCA with only two of the base-case four jurisdictions. The base case includes Butte County, and the Cities of Chico, Oroville, and Paradise. The low city participation case includes only Butte County and the City of Chico. Under the two-jurisdiction case, rates are slightly higher than under the four-jurisdiction case due to the fixed costs being spread over less load. The maximum rate savings that the CCA could offer to customers in the four-jurisdiction case is 3-6.7% in the first few years of operation. However, in the two-jurisdiction case, the maximum savings available for the CCA to offer to customers falls to 2.2-5.9% in the first years of operation. There is still sufficient room for the CCA to offer the 2% target rate savings over PG&E to customers. Additionally, annual reserves fall by 50% in the two-jurisdiction case when compared to the four-jurisdiction case, largely driven by the lower number of residential customers in the two-jurisdiction case. However, it should be noted that operating reserves targets can still be met comfortably under this scenario. Lastly, due to the lower load and thus lower power procurement needs, working capital needs are reduced by $500,000 when compared to the four-jurisdiction case.

Sensitivity Results

Exhibit 33 provides the results of the sensitivity analysis for the RPS scenario, which is the most likely portfolio for Butte County CCA to pursue initially given its goals.

Exhibit 33
Base Case Portfolio – Bundled Rates ($/kWh)
10-Year Levelized Average System Rate

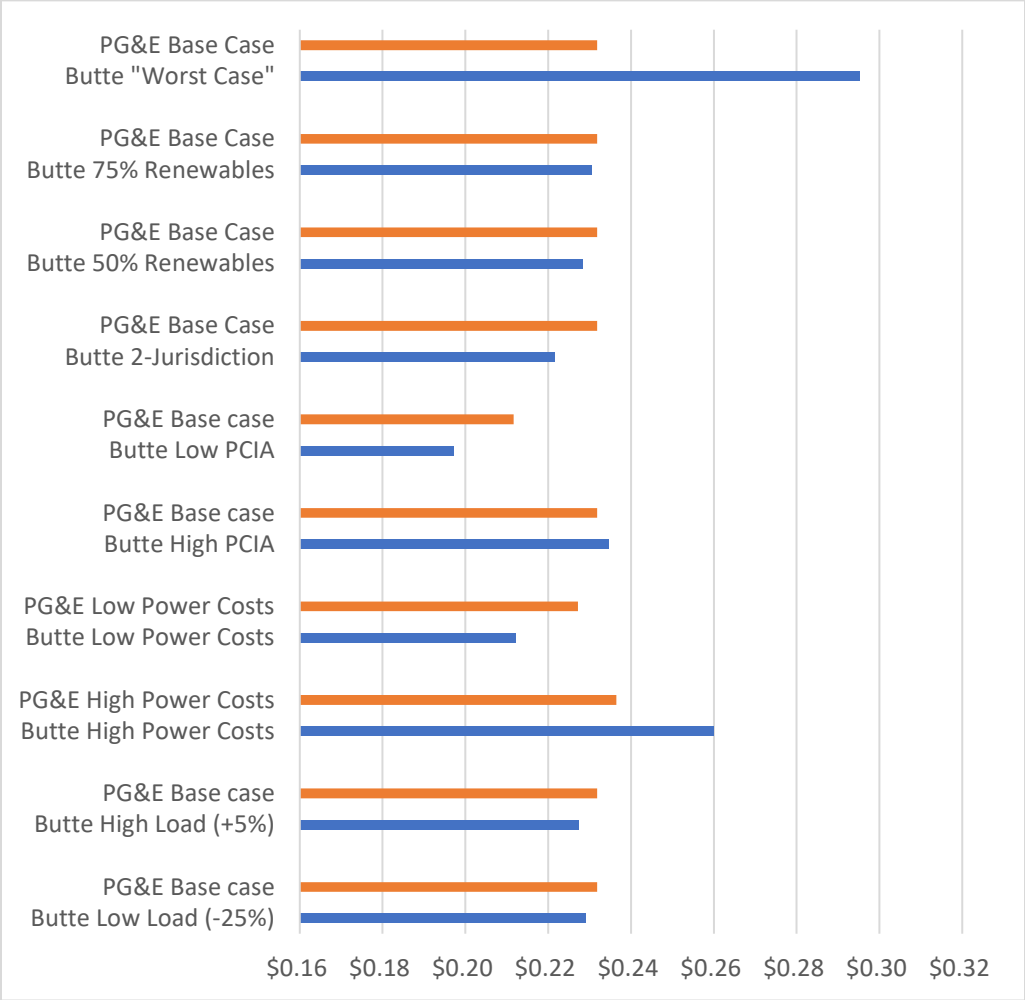


Exhibit 33 provides a comparison of the average system rate under several scenarios as defined below:

- PG&E Base Case, Butte Worst Case: Butte CCA high power supply costs, Low participation (70%), and High PCIA (6% annual escalation on average compared with 2%).
- PG&E Base Case, Butte 75% Renewable: Butte power supply mix is 75% renewable
- PG&E Base Case, Butte 50% Renewable: Butte power supply mix is 50% renewable
- PG&E Base Case, Butte 2 Jurisdiction: Butte County CCA includes only unincorporated areas and the City of Chico
- PG&E Base Case, Butte Low PCIA: PCIA average annual escalation rate is -2% compared with 2% in the base case
- PG&E Base Case, Butte High PCIA: PCIA average annual escalation rate is 6% compared with 2% in the base case. A higher than expected PCIA may occur as a result of the ongoing rulemaking process or PG&E experiences significant load losses due to CCA formation.

- PG&E Low Power Costs, Butte Low Power Costs: PG&E power costs are 2% lower than the base case, Butte CCA power costs are 25% lower than the base case. This might occur if market prices decrease significantly affecting both PG&E and the CCA. Note that lower power prices will likely increase the PCIA as well.
- PG&E High Power Costs, Butte High Power Costs: PG&E power costs are 2% Higher than the base case, Butte CCA power costs are 38% higher than the base case. This might occur if market prices increase significantly affecting both PG&E and the CCA.
- PG&E Base Case, Butte High Load (+5%): Butte CCA participation rate is approximately 95%.
- PG&E Base Case, Butte Low Load (-25%): Butte CCA a participation rate is approximately 70%.

This sensitivity shows that it is a significant risk to the CCA if the PCIA increases over 73 percent in 2019 and remains at that level into the future (high PCIA scenario).

The CCA's rates could also be higher than PG&E's under a "Worst Case" scenario. The "worst case" arises when the CCA does not achieve sufficient customer participation and CCA power supply costs are high, and PG&E charges a high PCIA.

Wholesale market prices for natural gas/electricity are currently at all-time lows. The probability of these market prices decreasing significantly from current levels is low. In addition, the CCA would need to manage its supply portfolio so that it is not exposed to unmanageable risks associated with power costs.

While the CCA will not be able to impact PG&E's generation rates, the CCA does have the opportunity to monitor and actively opine on the costs and methodology used to allocated non-bypassable costs to CCAs in PG&E's service area. Given recent history, this task will be shared with other CCAs and is an important and time-consuming task that can mitigate the impact on the CCA's costs. The PCIA is at a historic high, however, the design of the PCIA implies that the PCIA will decrease over time as PG&E's high-cost contracts expire and market prices increase. The only caveat is that there are regulatory and legislative pressures to continue adding costs to the PCIA calculation. However, the PCIA level should be fairly stable going forward as regulatory remedies are in play to stabilize the PCIA and the CCA vigilance in this area has increased markedly.

This Plan assumes a relatively high customer opt-out percentage (15 percent for non-residential customers) compared to the more modest opt-out rates experienced by California's actively operating CCAs, which is closer to 5 percent overall. While there is a possibility that the Participants' CCA does not reach the projected participation rates, careful monitoring and planning can reduce the potential impact of low loads.

The CCA should also consider implementing a rate stabilization fund so that short-term events that result in lower PG&E rates compared with the CCA rates can be mitigated with reserves rather than by rate increases. Reserves will help the CCA remain competitive and will provide rate stabilization for customers.

Summary and Recommendations

This Plan concludes that the formation of a CCA in Butte County is financially feasible and would yield considerable benefits for all participating County residents and businesses. These benefits could include 2 percent lower rates for electricity, although higher rate reductions are possible. At full build-out, a 2 percent rate reduction (a fraction of the total reduction possible) will add 42 jobs, generate over $3.6 million in additional GDP, and give the Cities and County and their residents greater control over their power supply, economic development and energy efficiency programs. The positive impacts on the County and its inhabitants of forming a CCA suggest that this effort should be pursued. No likely combination of sensitivities or phase-in/launch schedules will change this recommendation.

CCA Goals and Trade-Offs

The CCA governing board will need to prioritize the goals of the CCA based on the trade-offs between them. For example, CCAs generally offer rate discounts plus other programs. The rate discounts may be somewhat reduced as more programs are offered, depending on structure and available State funding, or as the renewable content of the CCA's portfolio increases.

Rate Reduction

The results of the feasibility study show that rates under a CCA are likely to be lower compared with PG&E's current and forecast generation rates. CCA customers should see no obvious changes in electric service other than the lower price and potentially more renewable power procurement, depending on the CCA's goals. Customers will pay the power supply charges set by the CCA and no longer pay the higher costs of PG&E power supply.

Given this Plan's findings, the CCA's rate setting can establish a goal of providing rates that are lower than the equivalent rates offered by PG&E even under the 50 and 75 percent renewable portfolios. The projected Butte County CCA and PG&E rates are illustrated in Exhibit 34.

Exhibit 34 Indicative Rate Comparison in $/kWh				
Rate Class	**2022 PG&E Bundled Rate***	**Indicative Butte RPS Bundled Rate**	**Indicative Butte 50% Renewable Bundled Rate**	**Indicative 75% Renewable Bundled Rate**
Residential	0.2033	0.2007	0.2019	0.2035
Small Commercial	0.2436	0.2440	0.2453	0.2469
Medium Commercial	0.2151	0.2122	0.2135	0.2152
Large Commercial	0.1807	0.1676	0.1688	0.1703
Street Lights	0.2184	0.2002	0.2011	0.2023
Agriculture	0.2405	0.2407	0.2418	0.2432
Industrial	0.1543	0.1395	0.1406	0.1420
Total	**0.2057**	**0.2016**	**0.2029**	**0.2044**
Initial Rate Savings in 2022 from PG&E Bundled Rate		**2.00%**	**1.50%**	**0.50%**
Maximum Rate Savings After Fully Operational		**3.9-4.4%**	**2.9-3.9%**	**0.9-1.4%**

*PG&E bundled average rate based on PG&E's 2018 Rates

Once the CCA gives notice to PG&E that it will commence service, the CCA customers will not be responsible for costs associated with PG&E's future electricity procurement contracts or power plant investments.[46] This is an advantage to the CCA customers as they will now have local control of power supply costs through the CCA.

Renewable Energy

A second option of forming a CCA will be an increase in the proportion of energy generated and supplied by renewable resources. The Plan includes procurement of renewable energy sufficient to meet 33 percent or more of the CCA's electricity needs. The majority of this renewable energy will be met by new renewable resources. By 2020, PG&E must procure a minimum of 33 percent of its customers' annual electricity usage from renewable resources due to the State Renewable Portfolio Standard and the Energy Action Plan requirements of the CPUC. The CCA governing board can decide whether to follow the same renewable goals or to implement more aggressive targets.

Energy Efficiency

Additionally, the CCA's governing board may decide to offer more comprehensive energy efficiency programs to its customers. The existing energy efficiency programs administered by PG&E are not expected to change as a result of forming a CCA. The CCA customers will continue to pay the public goods charges to PG&E which funds energy efficiency programs for all

[46] CCAs may be liable for a share of unbundled stranded costs from new generation, but would then receive associated Resource Adequacy credits.

customers, regardless of supplier. The energy efficiency programs ultimately planned for the CCA will be in addition to the level of investment that would continue in the absence of a CCA. Thus, the CCA has the potential for increased energy investment and savings with an attendant further reduction in emissions due to expanded energy efficiency programs.

Greenhouse Gas (GHG) Emission Reduction

A fifth option to consider would be reduced GHG emissions. Reduced GHG emissions could mean a lower GHG content power mix, or incentives for electric vehicle purchases. For the first, the amount of renewable power in PG&E's power supply portfolio is 30 percent and will rise to 33 percent by 2020. Based on power supply strategy described previously, the estimated GHG emission reductions are forecast to range from 0 to 36,000 tons CO_2e per year by 2020 assuming a 75 percent RPS target is achieved. The baseline for comparison is the RPS resource mix versus the 50 and 75 percent resource mixes. Exhibit 35 details these reductions.

Exhibit 35
Comparison of Average Annual GHG Emissions from Electricity, by Resource Portfolio (2020-2030)

	RPS 80% GHG-free	50% Renewable 88% GHG-free	75% Renewable 88% GHG-free
CO2 Emissions (Metric tons of CO_2e/year)[47]	89,812	53,887	53,887

A second method for reducing GHG emissions includes investments in electric vehicle charging stations or incentives for electric car purchases.

Economic Development Impacts

The analyses contained in this Plan has focused primarily on the direct effects of the CCA formation. However, in addition to direct effects, indirect economic effects increase the benefits of the CCA in the community. These indirect effects include increased local investments, increased disposable income due to bill savings, and the reduced costs of inputs to production (electricity)s.

Exhibit 36 shows the effects $5 million in electric bill savings will have on the County's economy. The $5 million rate savings represents the maximum bill savings per year achievable by through the County CCA where all 4 Participants are included. It is estimated that the electric bill savings can create approximately 42 additional jobs in the County with over $2.0 million in labor income. It is also projected that the total value added will be approximately $3.6 million and output close to $5.9 million.

[47] Methodology follows the "GHG Accounting Methodology for LSE Portfolio Development in the IRP 2017-18 Cycle" as proposed by the CPUC staff.

Exhibit 36 $5 Million Rate Savings Effects on the Butte County Economy				
Impact Type	**Employment**	**Labor Income**	**Total Value Added**	**Output**
Direct Effect	13.9	$788,000	$1,383,000	$2,239,000
Indirect Effect	3.7	$169,000	$267,000	$489,000
Induced Effect	24	$1,024,000	$1,902,000	$3,198,000
Total Effect	41.7	$1,981,000	$3,552,000	$5,926,000

These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand. From a production standpoint, lower energy prices reduce production costs and may increase company profits. The additional profits will also have a multiplier effect as firms hire additional labor, increase investment, or pay shareholders. The impacts estimated in Exhibit 35 are specific to industries located within Butte County and the interrelationships between the inputs and outputs of production.

In addition to increased economic activity due to electric bill savings, potential local projects can also create job and economic growth in the local economy. As an example of the macroeconomic activity caused by local DER deployment, this Plan assumes the installation of ten crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 10 MW. Overall, the building of this one solar project is projected to create $17.5 million in earnings and $38 million in output (GDP) in the local economy along with 327 jobs during construction and 3 full-time jobs ongoing.

Appendix A – Projected Schedule

Butte County CCA

CCA Launch Milestone Schedule

	2018					2019												2020				
Day		0	30	60	90	120	150	180	210	240	270	300	330	360	390	420	450	480	510	540	570	600
	August	September	October	November	December	January	February	March	April	May	June	July	August	September	October	November	December	January	February	March	April	May
Business Plan Completed																						
Governing Structure Determined/Formed																						
Participants Governing Bodies approval of Ordinance/Resolution for creation of CCA																						
Develop Implementation Plan																						
Participants' Governing Bodies approval of Implementaiton Plan																						
CCA submits binding notice of intent to IOU																						
File Implementation Plan with CPUC																						
CPUC certifies implementation plan**																						
Develop RFP for Power Supply & Data Management																						
Issue RFP for Power Supply & Data Management																						
Negotiate Financing/Line of Credit																						
Participants' Governing Bodies approval of Financing Arrangement																						
Select Power Supply and Data Management Consultants																						
Contract Negotiations with Consultants																						
Approval of Contracts with Power Supply & Data Management Consultants																						
CCA executes power services agreement with Power Services Provider																						
CCA executes data management services agreement with Data Manager																						
CCA finalizes initial rates																						
Establish credit worthiness with IOU																						
Satisfy IOU's Electronic Data Exchange requirements																						
CCA executes service agreement with IOU																						
CCA submits registration package to CPUC																						
Customer outreach																						
Opt Out notice 1																						
Opt Out Notice 2																						
Automatic enrollment of customers that have not opted out																						
Customers switched to CCA service on next scheduled meter read date																						
Opt Out notice 3																						
Opt Out Notice 4																						

**Represents maximum possible duration for CPUC review of implementation plan

Butte County CCA Financial ProForma 4 Entities Participating	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenues from Operations ($)											
Electric Sales Revenues	$47,406,695	$79,886,972	$82,432,531	$83,673,921	$83,890,121	$82,970,178	$82,265,356	$82,961,453	$85,117,787	$87,957,672	$90,750,710
Less Uncollected Accounts	$211,971	$370,172	$384,476	$382,847	$388,394	$391,127	$394,317	$405,218	$416,355	$427,303	$438,495
Total Revenues	$47,194,723	$79,516,799	$82,048,056	$83,291,074	$83,501,727	$82,579,051	$81,871,039	$82,556,235	$84,701,432	$87,530,369	$90,312,215
Cost of Operations ($)											
Cost of Energy	$38,121,662	$68,611,140	$71,396,083	$71,833,467	$73,233,500	$73,750,784	$74,306,992	$76,403,759	$78,495,283	$80,649,201	$82,799,307
Operating & Administrative											
Billing & Data Management	$732,677	$1,652,645	$1,696,824	$1,742,183	$1,788,755	$1,836,572	$1,885,667	$1,936,075	$1,987,830	$2,040,969	$2,095,528
PGE Fees	$252,845	$559,142	$562,832	$566,547	$570,286	$574,050	$577,839	$581,652	$585,491	$589,355	$593,245
Consulting Services	$1,477,300	$1,383,732	$1,411,407	$1,439,635	$1,468,427	$1,497,796	$1,527,752	$1,558,307	$1,589,473	$1,621,263	$1,653,688
Staffing	$1,789,638	$2,089,709	$2,131,503	$2,174,133	$2,217,615	$2,261,968	$2,307,207	$2,353,351	$2,400,418	$2,448,427	$2,497,395
General & Administrative expenses	$198,900	$130,050	$132,651	$135,304	$189,010	$140,770	$143,586	$146,457	$200,387	$152,374	$155,422
Debt Service	$553,934	$1,260,677	$1,260,677	$420,226	$0	$0	$0	$0	$0	$0	$0
Total O&A Costs	$5,005,294	$7,075,954	$7,195,893	$6,478,027	$6,234,094	$6,311,156	$6,442,051	$6,575,843	$6,763,599	$6,852,388	$6,995,278
Operating Reserves	$3,967,680	$3,784,354.69	$3,379,455	$4,933,624	$2,384,028	$0	$0	$0	$0	$0	$0
Total Cost & Reserves	**$47,094,636**	**$79,471,449**	**$81,971,431**	**$83,245,118**	**$81,851,622**	**$80,061,940**	**$80,749,043**	**$82,979,602**	**$85,258,882**	**$87,501,589**	**$89,794,585**
CCA Program Surplus/(Deficit)	$100,087	$45,351	$76,625	$45,956	$1,650,105	$2,517,111	$1,121,996	($423,367)	($557,450)	$28,780	$517,630
CCA Cumulative Reserves	$4,067,767	$7,897,473	$11,353,553	$16,333,132	$20,367,266	$22,884,377	$24,006,373	$23,583,006	$23,025,556	$23,054,336	$23,571,966
Reserve Additions											
Operating Reserve Contributions	$4,067,767	$3,829,706	$3,456,080	$4,979,580	$4,034,133	$2,517,111	$1,121,996	$0	$0	$28,780	$517,630
Cash from Financing	$6,100,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Additions	$10,167,767	$3,829,706	$3,456,080	$4,979,580	$4,034,133	$2,517,111	$1,121,996	$0	$0	$28,780	$517,630
Reserve Outlays											
Start-up Funding Payments + Bonds	$547,797	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital Repayment (Remair	$0	$0	$0	$2,556,793	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Reserve Outlays	$547,797	$0	$0	$2,556,793	$0	$0	$0	$0	$0	$0	$0
Rate Stabilization Reserve Balance	$9,619,970	$13,449,675	$16,905,755	$19,328,542	$23,362,675	$25,879,786	$27,001,782	$27,001,782	$27,001,782	$27,030,563	$27,548,193

Butte County CCA Financial ProForma 2 Entities Participating	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenues from Operations ($)											
Electric Sales Revenues	$38,112,404	$65,056,983	$66,417,838	$67,407,515	$67,280,071	$66,639,116	$65,976,705	$67,301,377	$69,519,494	$70,820,002	$73,149,862
Less Uncollected Accounts	$170,421	$298,188	$309,589	$307,501	$311,588	$313,778	$316,385	$325,100	$334,057	$342,759	$351,710
Total Revenues	$37,941,983	$64,758,795	$66,108,249	$67,100,014	$66,968,484	$66,325,338	$65,660,320	$66,976,277	$69,185,437	$70,477,243	$72,798,152
Cost of Operations ($)											
Cost of Energy	$29,864,593	$54,330,233	$56,535,511	$56,881,856	$57,990,482	$58,400,098	$58,840,535	$60,500,875	$62,157,064	$63,862,659	$65,565,236
Operating & Administrative											
Billing & Data Management	$578,938	$1,309,797	$1,344,811	$1,380,760	$1,417,671	$1,455,568	$1,494,478	$1,534,429	$1,575,447	$1,617,562	$1,660,802
PGE Fees	$199,790	$443,146	$446,070	$449,014	$451,978	$454,961	$457,964	$460,986	$464,029	$467,091	$470,174
Consulting Services	$1,477,300	$1,383,732	$1,411,407	$1,439,635	$1,468,427	$1,497,796	$1,527,752	$1,558,307	$1,589,473	$1,621,263	$1,653,688
Staffing	$1,789,638	$2,089,709	$2,131,503	$2,174,133	$2,217,615	$2,261,968	$2,307,207	$2,353,351	$2,400,418	$2,448,427	$2,497,395
General & Administrative expenses	$198,900	$130,050	$132,651	$135,304	$189,010	$140,770	$143,586	$146,457	$200,387	$152,374	$155,422
Debt Service	$553,934	$1,260,677	$1,260,677	$420,226	$0	$0	$0	$0	$0	$0	$0
Total O&A Costs	$4,798,500	$6,617,110	$6,727,118	$5,999,072	$5,744,702	$5,811,063	$5,930,987	$6,053,530	$6,229,754	$6,306,717	$6,437,481
Operating Reserves	$3,189,005	$3,047,367.15	$2,720,293	$3,961,498	$1,912,056	$0	$0	$0	$0	$0	$0
Total Cost & Reserves	**$37,852,097**	**$63,994,710**	**$65,982,922**	**$66,842,427**	**$65,647,239**	**$64,211,160**	**$64,771,522**	**$66,554,406**	**$68,386,817**	**$70,169,376**	**$72,002,718**
CCA Program Surplus/(Deficit)	$89,886	$764,085	$125,327	$257,588	$1,321,244	$2,114,178	$888,798	$421,871	$798,620	$307,867	$795,434
CCA Cumulative Reserves	$3,278,891	$7,090,343	$9,935,963	$14,155,049	$17,388,349	$19,502,526	$20,391,325	$20,813,196	$21,611,816	$21,919,683	$22,715,118
Reserve Additions											
Operating Reserve Contributions	$3,278,891	$3,811,452	$2,845,620	$4,219,086	$3,233,300	$2,114,178	$888,798	$421,871	$798,620	$307,867	$795,434
Cash from Financing	$6,100,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Additions	$9,378,891	$3,811,452	$2,845,620	$4,219,086	$3,233,300	$2,114,178	$888,798	$421,871	$798,620	$307,867	$795,434
Reserve Outlays											
Start-up Funding Payments + Bonds -	$454,726	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital Repayment (Remair	$0	$0	$0	$2,556,793	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Reserve Outlays	$454,726	$0	$0	$2,556,793	$0	$0	$0	$0	$0	$0	$0
Rate Stabilization Reserve Balance	$8,924,165	$12,735,617	$15,581,237	$17,243,530	$20,476,830	$22,591,008	$23,479,806	$23,901,678	$24,700,298	$25,008,165	$25,803,599

Appendix C – Staffing and Infrastructure Detail

Costs by Year *Full Staff* *4 Participants*	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cost of Energy	$38,121,662	$68,611,140	$71,396,083	$71,833,467	$73,233,500	$73,750,784	$74,306,992	$76,403,759	$78,495,283	$80,649,201	$82,799,307
Billing and Data Management	$732,677	$1,652,645	$1,696,824	$1,742,183	$1,788,755	$1,836,572	$1,885,667	$1,936,075	$1,987,830	$2,040,969	$2,095,528
PG&E Fees	$252,845	$559,142	$562,832	$566,547	$570,286	$574,050	$577,839	$581,652	$585,491	$589,355	$593,245
General & Administrative Expenses											
Computers	$51,000	$0	$0	$0	$51,000	$0	$0	$0	$51,000	$0	$0
Furnishings	$20,400	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Office Space	$15,300	$15,606	$15,918	$16,236	$16,561	$16,892	$17,230	$17,575	$17,926	$18,285	$18,651
Utilities and other Office supplies	$10,200	$10,404	$10,612	$10,824	$11,041	$11,262	$11,487	$11,717	$11,951	$12,190	$12,434
Miscellaneous	$102,000	$104,040	$106,121	$108,243	$110,408	$112,616	$114,869	$117,166	$119,509	$121,899	$124,337
Total Infrastructure Costs	**$198,900**	**$130,050**	**$132,651**	**$135,304**	**$189,010**	**$140,770**	**$143,586**	**$146,457**	**$200,387**	**$152,374**	**$155,422**
Consulting Services											
Legal/Regulatory	$275,400	$374,544	$382,035	$389,676	$397,469	$405,418	$413,527	$421,797	$430,233	$438,838	$447,615
Advertising/Communication	$187,000	$104,040	$106,121	$108,243	$110,408	$112,616	$114,869	$117,166	$119,509	$121,899	$124,337
Technical Consultants	$122,400	$124,848	$127,345	$129,892	$132,490	$135,139	$137,842	$140,599	$143,411	$146,279	$149,205
Data Management	$732,677	$1,652,645	$1,696,824	$1,742,183	$1,788,755	$1,836,572	$1,885,667	$1,936,075	$1,987,830	$2,040,969	$2,095,528
Financial Consulting	$510,000	$520,200	$530,604	$541,216	$552,040	$563,081	$574,343	$585,830	$597,546	$609,497	$621,687
CalCCA Annual Dues	$76,500	$104,040	$106,121	$108,243	$110,408	$112,616	$114,869	$117,166	$119,509	$121,899	$124,337
Other consulting/city functions	$306,000	$156,060	$159,181	$162,365	$165,612	$168,924	$172,303	$175,749	$179,264	$182,849	$186,506
Total Consulting Costs	**$2,209,977**	**$3,036,377**	**$3,108,230**	**$3,181,818**	**$3,257,182**	**$3,334,368**	**$3,413,419**	**$3,494,382**	**$3,577,303**	**$3,662,231**	**$3,749,216**
Staffing											
Chief Executive Officer	$306,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698	$373,012
Director of Power Resources	$179,005	$243,447	$248,316	$253,282	$258,348	$263,515	$268,785	$274,160	$279,644	$285,237	$290,941
Director of Administration and Finance	$179,005	$243,446	$248,315	$253,282	$258,347	$263,514	$268,784	$274,160	$279,643	$285,236	$290,941
Director of Marketing and Public Affairs	$238,673	$243,447	$248,316	$253,282	$258,348	$263,515	$268,785	$274,160	$279,644	$285,237	$290,941
Power Supply Compliance Specialist	$145,610	$198,030	$201,990	$206,030	$210,151	$214,354	$218,641	$223,014	$227,474	$232,023	$236,664
Community Outreach Manager	$145,610	$198,030	$201,990	$206,030	$210,151	$214,354	$218,641	$223,014	$227,474	$232,023	$236,664
Account Service Manager	$187,444	$191,193	$195,017	$198,917	$202,895	$206,953	$211,092	$215,314	$219,620	$224,013	$228,493
Account Representatives	$112,162	$114,405	$116,693	$119,027	$121,408	$123,836	$126,313	$128,839	$131,416	$134,044	$136,725
Communication Specialists	$168,071	$171,432	$174,861	$178,358	$181,925	$185,564	$189,275	$193,061	$196,922	$200,860	$204,877
Administrative Analysts	$128,058	$174,159	$177,643	$181,195	$184,819	$188,516	$192,286	$196,132	$200,054	$204,056	$208,137
Total Staffing Costs	**$1,789,638**	**$2,089,709**	**$2,131,503**	**$2,174,133**	**$2,217,615**	**$2,261,968**	**$2,307,207**	**$2,353,351**	**$2,400,418**	**$2,448,427**	**$2,497,395**
Debt Service	$553,934	$1,260,677	$1,260,677	$1,260,677	$1,260,677	$706,743	$0	$0	$0	$0	$0
Total Expenses	**$43,859,633**	**$77,339,739**	**$80,288,799**	**$80,894,128**	**$82,517,025**	**$82,605,255**	**$82,634,710**	**$84,915,677**	**$87,246,712**	**$89,542,557**	**$91,890,112**

Costs by Year *Full Staff* *2 Participants*	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cost of Energy	$29,864,593	$54,330,233	$56,535,511	$56,881,856	$57,990,482	$58,400,098	$58,840,535	$60,500,875	$62,157,064	$63,862,659	$65,565,236
Billing and Data Management	$578,938	$1,309,797	$1,344,811	$1,380,760	$1,417,671	$1,455,568	$1,494,478	$1,534,429	$1,575,447	$1,617,562	$1,660,802
PG&E Fees	$199,790	$443,146	$446,070	$449,014	$451,978	$454,961	$457,964	$460,986	$464,029	$467,091	$470,174
General & Administrative Expenses											
Computers	$51,000	$0	$0	$0	$51,000	$0	$0	$0	$51,000	$0	$0
Furnishings	$20,400	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Office Space	$15,300	$15,606	$15,918	$16,236	$16,561	$16,892	$17,230	$17,575	$17,926	$18,285	$18,651
Utilities and other Office supplies	$10,200	$10,404	$10,612	$10,824	$11,041	$11,262	$11,487	$11,717	$11,951	$12,190	$12,434
Miscellaneous	$102,000	$104,040	$106,121	$108,243	$110,408	$112,616	$114,869	$117,166	$119,509	$121,899	$124,337
Total Infrastructure Costs	**$198,900**	**$130,050**	**$132,651**	**$135,304**	**$189,010**	**$140,770**	**$143,586**	**$146,457**	**$200,387**	**$152,374**	**$155,422**
Consulting Services											
Legal/Regulatory	$275,400	$374,544	$382,035	$389,676	$397,469	$405,418	$413,527	$421,797	$430,233	$438,838	$447,615
Advertising/Communication	$187,000	$104,040	$106,121	$108,243	$110,408	$112,616	$114,869	$117,166	$119,509	$121,899	$124,337
Technical Consultants	$122,400	$124,848	$127,345	$129,892	$132,490	$135,139	$137,842	$140,599	$143,411	$146,279	$149,205
Data Management	$578,938	$1,309,797	$1,344,811	$1,380,760	$1,417,671	$1,455,568	$1,494,478	$1,534,429	$1,575,447	$1,617,562	$1,660,802
Financial Consulting	$510,000	$520,200	$530,604	$541,216	$552,040	$563,081	$574,343	$585,830	$597,546	$609,497	$621,687
CalCCA Annual Dues	$76,500	$104,040	$106,121	$108,243	$110,408	$112,616	$114,869	$117,166	$119,509	$121,899	$124,337
Other consulting/city functions	$306,000	$156,060	$159,181	$162,365	$165,612	$168,924	$172,303	$175,749	$179,264	$182,849	$186,506
Total Consulting Costs	**$2,056,238**	**$2,693,529**	**$2,756,217**	**$2,820,395**	**$2,886,098**	**$2,953,364**	**$3,022,230**	**$3,092,736**	**$3,164,920**	**$3,238,824**	**$3,314,490**
Staffing											
Chief Executive Officer	$306,000	$312,120	$318,362	$324,730	$331,224	$337,849	$344,606	$351,498	$358,528	$365,698	$373,012
Director of Power Resources	$179,005	$243,447	$248,316	$253,282	$258,348	$263,515	$268,785	$274,160	$279,644	$285,237	$290,941
Director of Administration and Finance	$179,005	$243,446	$248,315	$253,282	$258,347	$263,514	$268,784	$274,160	$279,643	$285,236	$290,941
Director of Marketing and Public Affairs	$238,673	$243,447	$248,316	$253,282	$258,348	$263,515	$268,785	$274,160	$279,644	$285,237	$290,941
Power Supply Compliance Specialist	$145,610	$198,030	$201,990	$206,030	$210,151	$214,354	$218,641	$223,014	$227,474	$232,023	$236,664
Community Outreach Manager	$145,610	$198,030	$201,990	$206,030	$210,151	$214,354	$218,641	$223,014	$227,474	$232,023	$236,664
Account Service Manager	$187,444	$191,193	$195,017	$198,917	$202,895	$206,953	$211,092	$215,314	$219,620	$224,013	$228,493
Account Representatives	$112,162	$114,405	$116,693	$119,027	$121,408	$123,836	$126,313	$128,839	$131,416	$134,044	$136,725
Communication Specialists	$168,071	$171,432	$174,861	$178,358	$181,925	$185,564	$189,275	$193,061	$196,922	$200,860	$204,877
Administrative Analysts	$128,058	$174,159	$177,643	$181,195	$184,819	$188,516	$192,286	$196,132	$200,054	$204,056	$208,137
Total Staffing Costs	**$1,789,638**	**$2,089,709**	**$2,131,503**	**$2,174,133**	**$2,217,615**	**$2,261,968**	**$2,307,207**	**$2,353,351**	**$2,400,418**	**$2,448,427**	**$2,497,395**
Debt Service	$553,934	$1,260,677	$1,260,677	$1,260,677	$1,260,677	$706,743	$0	$0	$0	$0	$0
Total Expenses	**$35,242,030**	**$62,257,140**	**$64,607,440**	**$65,102,140**	**$66,413,531**	**$66,373,471**	**$66,266,000**	**$68,088,834**	**$69,962,264**	**$71,786,938**	**$73,663,520**

Base Case: 4 Participants

Butte County CCA *Cash Flow - 2020* *RPS Base Case - 2% Rate Savings Target*	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cash Flow												
Revenues												
CCA Generation Revenues	$0	$0	$0	$2,517,325	$2,722,748	$2,954,468	$3,221,482	$9,263,122	$7,532,591	$6,261,792	$6,210,965	$6,725,492
CCA PCIA Revenue	$0	$0	$0	$775,920	$847,042	$930,729	$1,018,060	$3,219,000	$2,592,464	$2,149,020	$2,134,173	$2,326,585
CCA Revenues based on Projected Rates	**$0**	**$0**	**$0**	**$3,293,244**	**$3,569,791**	**$3,885,197**	**$4,239,542**	**$12,482,122**	**$10,125,055**	**$8,410,812**	**$8,345,138**	**$9,052,077**
Expenses												
Power Supply												
Power Procurement	$0	$0	$0	$1,813,994	$1,946,760	$2,169,076	$2,648,019	$7,804,048	$6,348,223	$5,009,405	$4,936,008	$5,446,130
Non-bypassable charges	$0	$0	$0	$775,920	$847,042	$930,729	$1,018,060	$3,219,000	$2,592,464	$2,149,020	$2,134,173	$2,326,585
Total Power Supply	$0	$0	$0	$2,589,914	$2,793,802	$3,099,805	$3,666,079	$11,023,048	$8,940,687	$7,158,425	$7,070,181	$7,772,715
CCA Program Costs												
Data Management	$0	$0	$0	$15,384	$15,379	$15,382	$15,392	$135,105	$133,971	$134,041	$133,930	$134,093
IOU Fees (including Billing)	$0	$0	$0	$5,309	$5,307	$5,308	$5,312	$46,624	$46,233	$46,257	$46,219	$46,275
Consultants	$78,200	$95,200	$95,200	$134,300	$134,300	$134,300	$134,300	$134,300	$134,300	$134,300	$134,300	$134,300
Uncollected accounts	$0	$0	$0	$10,853	$11,577	$12,689	$15,084	$41,070	$33,789	$27,382	$27,015	$29,566
Staffing	$84,362	$84,362	$84,362	$170,728	$170,728	$170,728	$170,728	$170,728	$170,728	$170,728	$170,728	$170,728
General & Admin	$46,325	$10,625	$10,625	$46,325	$10,625	$10,625	$10,625	$10,625	$10,625	$10,625	$10,625	$10,625
Debt Payment	$0	$0	$0	$0	$47,753	$47,753	$47,753	$47,753	$47,753	$105,056	$105,056	$105,056
CPUC Bond	$0	$0	$0	$0	$0	$100,000	$0	$0	$0	$0	$0	$0
PG&E Bond	$0	$0	$0	$0	$447,797	$0	$0	$0	$0	$0	$0	$0
Total Expenses (excl PCIA)	$208,887	$190,187	$190,187	$2,181,509	$2,774,848	$2,650,479	$3,031,821	$8,255,149	$6,791,651	$5,503,753	$5,429,951	$5,942,681
Reserve Needs												
Beginning Balance	0	$391,113	$200,925	$10,738	$2,127,838	($529,621)	($455,841)	($301,362)	($581,119)	($2,741,085)	($454,575)	$1,440,739
Additions	$0	$0	$0	$0	$0	$2,517,325	$2,722,748	$2,954,468	$3,221,482	$9,263,122	$7,532,591	$6,261,792
Financing	$600,000	$0	$0	$2,500,000	$0	$0	$0	$0	$3,000,000	$0	$0	$0
Working capital repayment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reductions	$208,887	$190,187	$190,187	$382,899	$2,657,460	$2,443,544	$2,568,269	$3,234,225	$8,381,447	$6,976,612	$5,637,277	$5,566,651
Ending Balance	$391,113	$200,925	$10,738	$2,127,838	($529,621)	($455,841)	($301,362)	($581,119)	($2,741,085)	($454,575)	$1,440,739	$2,135,879
Cash flow												
Beginning Balance	$0	$391,113	$200,925	$10,738	$2,127,838	($529,621)	($455,841)	($301,362)	($581,119)	($2,741,085)	($454,575)	$1,440,739
Additions												
Revenues	$0	$0	$0	$0	$0	$2,517,325	$2,722,748	$2,954,468	$3,221,482	$9,263,122	$7,532,591	$6,261,792
Financing	$600,000	$0	$0	$2,500,000	$0	$0	$0	$0	$3,000,000	$0	$0	$0
Reductions including debt service	$208,887	$190,187	$190,187	$382,899	$2,657,460	$2,443,544	$2,568,269	$3,234,225	$8,381,447	$6,976,612	$5,637,277	$5,566,651
Ending Balance	$391,113	$200,925	$10,738	$2,127,838	($529,621)	($455,841)	($301,362)	($581,119)	($2,741,085)	($454,575)	$1,440,739	$2,135,879

Butte County CCA												
Cash Flow - 2021												
RPS Base Case - 2% Rate Savings Target	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Cash Flow												
Revenues												
CCA Generation Revenues	$6,270,169	$5,664,880	$5,247,226	$5,469,416	$6,395,218	$7,771,402	$8,882,523	$8,800,547	$7,156,321	$5,948,951	$5,900,783	$6,389,735
CCA PCIA Revenue	$2,737,838	$2,455,458	$2,263,491	$2,351,488	$2,788,934	$3,431,363	$3,938,847	$3,888,295	$3,131,489	$2,595,844	$2,577,910	$2,810,329
CCA Revenues based on Projected Rates	**$9,008,008**	**$8,120,338**	**$7,510,717**	**$7,820,904**	**$9,184,152**	**$11,202,765**	**$12,821,370**	**$12,688,842**	**$10,287,810**	**$8,544,795**	**$8,478,693**	**$9,200,064**
Expenses												
Power Supply												
Power Procurement	$5,521,392	$4,914,885	$4,439,747	$4,372,924	$5,054,624	$6,272,487	$7,709,501	$7,849,983	$6,410,744	$5,219,398	$5,138,749	$5,706,707
Non-bypassable charges	$2,737,838	$2,455,458	$2,263,491	$2,351,488	$2,788,934	$3,431,363	$3,938,847	$3,888,295	$3,131,489	$2,595,844	$2,577,910	$2,810,329
Total Power Supply	$8,259,231	$7,370,342	$6,703,238	$6,724,412	$7,843,558	$9,703,850	$11,648,348	$11,738,278	$9,542,233	$7,815,243	$7,716,659	$8,517,036
CCA Program Costs												
Data Management	$137,349	$137,016	$137,060	$137,192	$137,503	$138,988	$138,457	$138,716	$137,552	$137,625	$137,510	$137,678
IOU Fees (including Billing)	$46,470	$46,357	$46,372	$46,416	$46,521	$47,024	$46,844	$46,932	$46,538	$46,563	$46,524	$46,581
Consultants	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311
Uncollected accounts	$29,866	$26,833	$24,457	$24,123	$27,532	$33,624	$40,808	$41,511	$34,313	$28,357	$27,953	$30,793
Staffing	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142
General & Admin	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838
Debt Payment	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056
CPUC Bond	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E Bond	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenses (excl PCIA)	$6,003,075	$5,393,422	$4,915,923	$4,848,811	$5,534,025	$6,758,482	$8,202,501	$8,343,774	$6,896,942	$5,699,665	$5,618,573	$6,189,428
Reserve Needs												
Beginning Balance	$2,135,879	$2,281,682	$2,870,228	$3,612,276	$4,224,331	$4,481,729	$4,271,539	$3,762,814	$3,192,208	$3,600,996	$5,372,908	$6,692,497
Additions	$6,210,965	$6,725,492	$6,270,169	$5,664,880	$5,247,226	$5,469,416	$6,395,218	$7,771,402	$8,882,523	$8,800,547	$7,156,321	$5,948,951
Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working capital repayment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reductions	$6,065,162	$6,136,945	$5,528,121	$5,052,826	$4,989,828	$5,679,606	$6,903,943	$8,342,008	$8,473,734	$7,028,635	$5,836,733	$5,759,148
Ending Balance	$2,281,682	$2,870,228	$3,612,276	$4,224,331	$4,481,729	$4,271,539	$3,762,814	$3,192,208	$3,600,996	$5,372,908	$6,692,497	$6,882,299
Cash flow												
Beginning Balance	$2,135,879	$2,281,682	$2,870,228	$3,612,276	$4,224,331	$4,481,729	$4,271,539	$3,762,814	$3,192,208	$3,600,996	$5,372,908	$6,692,497
Additions												
Revenues	$6,210,965	$6,725,492	$6,270,169	$5,664,880	$5,247,226	$5,469,416	$6,395,218	$7,771,402	$8,882,523	$8,800,547	$7,156,321	$5,948,951
Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reductions including debt service	$6,065,162	$6,136,945	$5,528,121	$5,052,826	$4,989,828	$5,679,606	$6,903,943	$8,342,008	$8,473,734	$7,028,635	$5,836,733	$5,759,148
Ending Balance	$2,281,682	$2,870,228	$3,612,276	$4,224,331	$4,481,729	$4,271,539	$3,762,814	$3,192,208	$3,600,996	$5,372,908	$6,692,497	$6,882,299

2 Participants: Chico and Unincorporated Butte County

Butte County CCA												
Cash Flow - 2020												
RPS Base Case - 2% Rate Savings Target	**2020**	**2020**	**2020**	**2020**	**2020**	**2020**	**2020**	**2020**	**2020**	**2020**	**2020**	**2020**
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Cash Flow												
Revenues												
CCA Generation Revenues	$0	$0	$0	$1,931,664	$2,098,206	$2,256,904	$2,460,004	$7,605,046	$6,180,459	$5,161,022	$5,009,616	$5,412,874
CCA PCIA Revenue	$0	$0	$0	$472,937	$518,845	$566,055	$618,629	$2,123,046	$1,708,668	$1,422,024	$1,381,787	$1,503,359
CCA Revenues based on Projected Rates	**$0**	**$0**	**$0**	**$2,404,601**	**$2,617,051**	**$2,822,959**	**$3,078,633**	**$9,728,092**	**$7,889,127**	**$6,583,046**	**$6,391,403**	**$6,916,233**
Expenses												
Power Supply												
Power Procurement	$0	$0	$0	$1,353,882	$1,458,792	$1,610,241	$1,965,730	$6,244,250	$5,077,074	$4,026,474	$3,882,221	$4,276,254
Non-bypassable charges	$0	$0	$0	$472,937	$518,845	$566,055	$618,629	$2,123,046	$1,708,668	$1,422,024	$1,381,787	$1,503,359
Total Power Supply	$0	$0	$0	$1,826,819	$1,977,637	$2,176,296	$2,584,359	$8,367,296	$6,785,742	$5,448,498	$5,264,009	$5,779,613
CCA Program Costs												
Data Management	$0	$0	$0	$11,833	$11,825	$11,834	$11,846	$107,224	$106,098	$106,081	$106,015	$106,181
IOU Fees (including Billing)	$0	$0	$0	$4,083	$4,081	$4,084	$4,088	$37,003	$36,614	$36,608	$36,586	$36,643
Consultants	$78,200	$95,200	$95,200	$134,300	$134,300	$134,300	$134,300	$134,300	$134,300	$134,300	$134,300	$134,300
Uncollected accounts	$0	$0	$0	$8,547	$9,131	$9,889	$11,666	$33,223	$27,385	$22,419	$21,698	$23,668
Staffing	$84,362	$84,362	$84,362	$170,728	$170,728	$170,728	$170,728	$170,728	$170,728	$170,728	$170,728	$170,728
General & Admin	$46,325	$10,625	$10,625	$46,325	$10,625	$10,625	$10,625	$10,625	$10,625	$10,625	$10,625	$10,625
Debt Payment	$0	$0	$0	$0	$47,753	$47,753	$47,753	$47,753	$47,753	$105,056	$105,056	$105,056
CPUC Bond	$0	$0	$0	$0	$0	$100,000	$0	$0	$0	$0	$0	$0
PG&E Bond	$0	$0	$0	$0	$354,726	$0	$0	$0	$0	$0	$0	$0
Total Expenses (excl PCIA)	$208,887	$190,187	$190,187	$1,717,865	$2,190,135	$2,087,619	$2,344,890	$6,677,882	$5,504,480	$4,506,211	$4,361,214	$4,757,274
Reserve Needs												
Beginning Balance	0	$391,113	$200,925	$10,738	$2,134,922	$37,871	$21,532	$118,491	($131,191)	($1,448,942)	$493,213	$2,062,190
Additions	$0	$0	$0	$0	$0	$1,931,664	$2,098,206	$2,256,904	$2,460,004	$7,605,046	$6,180,459	$5,161,022
Financing	$600,000	$0	$0	$2,500,000	$0	$0	$0	$0	$3,000,000	$0	$0	$0
Working capital repayment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reductions	$208,887	$190,187	$190,187	$375,815	$2,097,051	$1,948,003	$2,001,247	$2,506,586	$6,777,754	$5,662,892	$4,611,481	$4,469,423
Ending Balance	$391,113	$200,925	$10,738	$2,134,922	$37,871	$21,532	$118,491	($131,191)	($1,448,942)	$493,213	$2,062,190	$2,753,789
Cash flow												
Beginning Balance	$0	$391,113	$200,925	$10,738	$2,134,922	$37,871	$21,532	$118,491	($131,191)	($1,448,942)	$493,213	$2,062,190
Additions												
Revenues	$0	$0	$0	$0	$0	$1,931,664	$2,098,206	$2,256,904	$2,460,004	$7,605,046	$6,180,459	$5,161,022
Financing	$600,000	$0	$0	$2,500,000	$0	$0	$0	$0	$3,000,000	$0	$0	$0
Reductions including debt service	$208,887	$190,187	$190,187	$375,815	$2,097,051	$1,948,003	$2,001,247	$2,506,586	$6,777,754	$5,662,892	$4,611,481	$4,469,423
Ending Balance	$391,113	$200,925	$10,738	$2,134,922	$37,871	$21,532	$118,491	($131,191)	($1,448,942)	$493,213	$2,062,190	$2,753,789

Butte County CCA												
Cash Flow - 2021												
RPS Base Case - 2% Rate Savings Target	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**	**2021**
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Cash Flow												
Revenues												
CCA Generation Revenues	$5,062,316	$4,559,756	$4,203,541	$4,411,247	$5,241,371	$6,362,632	$7,262,270	$7,241,355	$5,884,803	$4,914,084	$4,770,031	$5,154,112
CCA PCIA Revenue	$1,444,605	$1,291,601	$1,184,934	$1,240,094	$1,496,851	$1,841,564	$2,110,448	$2,094,317	$1,685,546	$1,402,781	$1,363,089	$1,483,016
CCA Revenues based on Projected Rates	**$6,506,921**	**$5,851,357**	**$5,388,475**	**$5,651,341**	**$6,738,222**	**$8,204,196**	**$9,372,719**	**$9,335,672**	**$7,570,349**	**$6,316,865**	**$6,133,120**	**$6,637,128**
Expenses												
Power Supply												
Power Procurement	$4,337,654	$3,845,580	$3,454,634	$3,424,473	$4,023,901	$4,991,827	$6,128,856	$6,281,004	$5,127,076	$4,195,263	$4,041,680	$4,480,856
Non-bypassable charges	$1,444,605	$1,291,601	$1,184,934	$1,240,094	$1,496,851	$1,841,564	$2,110,448	$2,094,317	$1,685,546	$1,402,781	$1,363,089	$1,483,016
Total Power Supply	$5,782,259	$5,137,181	$4,639,568	$4,664,568	$5,520,752	$6,833,391	$8,239,304	$8,375,321	$6,812,622	$5,598,044	$5,404,768	$5,963,872
CCA Program Costs												
Data Management	$108,802	$108,490	$108,607	$108,672	$109,020	$110,477	$109,918	$110,091	$108,935	$108,917	$108,849	$109,020
IOU Fees (including Billing)	$36,811	$36,705	$36,745	$36,767	$36,885	$37,378	$37,189	$37,247	$36,856	$36,850	$36,827	$36,885
Consultants	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311	$115,311
Uncollected accounts	$23,899	$21,438	$19,484	$19,333	$22,331	$27,173	$32,857	$33,618	$27,846	$23,187	$22,419	$24,615
Staffing	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142	$174,142
General & Admin	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838	$10,838
Debt Payment	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056	$105,056
CPUC Bond	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E Bond	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenses (excl PCIA)	$4,803,712	$4,309,071	$3,916,210	$3,885,921	$4,488,464	$5,461,725	$6,604,249	$6,757,217	$5,597,126	$4,660,648	$4,506,273	$4,947,704
Reserve Needs												
Beginning Balance	$2,753,789	$2,912,292	$3,415,531	$4,062,084	$4,597,087	$4,802,572	$4,609,543	$4,273,775	$3,921,248	$4,323,530	$5,863,507	$6,979,603
Additions	$5,009,616	$5,412,874	$5,062,316	$4,559,756	$4,203,541	$4,411,247	$5,241,371	$6,362,632	$7,262,270	$7,241,355	$5,884,803	$4,914,084
Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working capital repayment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reductions	$4,851,113	$4,909,635	$4,415,763	$4,024,753	$3,998,056	$4,604,277	$5,577,138	$6,715,159	$6,859,988	$5,701,378	$4,768,706	$4,617,547
Ending Balance	$2,912,292	$3,415,531	$4,062,084	$4,597,087	$4,802,572	$4,609,543	$4,273,775	$3,921,248	$4,323,530	$5,863,507	$6,979,603	$7,276,141
Cash flow												
Beginning Balance	$2,753,789	$2,912,292	$3,415,531	$4,062,084	$4,597,087	$4,802,572	$4,609,543	$4,273,775	$3,921,248	$4,323,530	$5,863,507	$6,979,603
Additions												
Revenues	$5,009,616	$5,412,874	$5,062,316	$4,559,756	$4,203,541	$4,411,247	$5,241,371	$6,362,632	$7,262,270	$7,241,355	$5,884,803	$4,914,084
Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reductions including debt service	$4,851,113	$4,909,635	$4,415,763	$4,024,753	$3,998,056	$4,604,277	$5,577,138	$6,715,159	$6,859,988	$5,701,378	$4,768,706	$4,617,547
Ending Balance	$2,912,292	$3,415,531	$4,062,084	$4,597,087	$4,802,572	$4,609,543	$4,273,775	$3,921,248	$4,323,530	$5,863,507	$6,979,603	$7,276,141

Appendix E – Glossary

aMW: Average annual Megawatt. A unit of energy output over a year that is equal to the energy produced by the continuous operation of one megawatt of capacity over a period of time (8,760 megawatt-hours).

Basis Difference (Natural Gas): The difference between the price of natural gas at the Henry Hub natural gas distribution point in Erath, Louisiana, which serves as a central pricing point for natural gas futures, and the natural gas price at another hub location (such as for Southern California).

Buckets: Buckets 1-3 refer to different types of renewable energy contracts according to the Renewable Portfolio Standards requirements. Bucket 1 are traditional contracts for delivery of electricity directly from a generator within or immediately connected to California. These are the most valuable and make up the majority of the RECS that are required for LSEs to be RPS compliant. Buckets 2 and 3 have different levels of intermediation between the generation and delivery of the energy from the generating resources.

Bundled Customers: Electricity customers who receive all their services (transmission, distribution and supply) from the Investor-Owned Utility.

California Independent System Operator (CAISO): The organization responsible for managing the electricity grid and system reliability within the former service territories of the three California IOUs.

California Clean Power (CCP): A private company providing wholesale supply and other services to CCAs.

California Energy Commission (CEC): The state regulatory agency with primary responsibility for enforcing the Renewable Portfolio Standards law as well as a number of other, electric-industry related rules and policies.

California Public Utilities Commission (CPUC): The state agency with primary responsibility for regulating IOUs, as well as Direct Access (ESP) and CCA entities.

Capacity Factor: the ratio of an electricity generating resource's actual output over a period of time to its potential output if it were possible to operate at full nameplate capacity continuously over the same period. Intermittent renewable resources, like wind and solar, typically have lower capacity factors than traditional fossil fuel plants because the wind and sun do not blow or shine consistently.

CleanPowerSF: CCA program serving customers within the City of San Francisco. CleanPowerSF began service to 7,800 "Phase 1" customers in May 2016.

Climate Zone: A geographic area with distinct climate patterns necessitating varied energy demands for heating and cooling.

Coincident Peak: Demand for electricity among a group of customers that coincides with peak total demand on the system.

Community Choice Aggregation (CCA): Method available through California law to allow Cities and Counties to aggregate their citizens and become their electric generation provider.

Community Choice Energy: A City, County or Joint Powers Agency procuring wholesale power to supply to retail customers.

Community Choice Partners: A private company providing services to CCAs in California.

Congestion Revenue Rights (CRRs): Financial rights that are allocated to Load Serving Entities to offset differences between the prices where their generation is located and the price that they pay to serve their load. These rights may also be bought and sold through an auction process. CRRs are part of the CAISO market design.

Demand Side Resources: Energy efficiency and load management programs that reduce the amount of energy that would otherwise be consumed by a customer of an electric utility.

Demand Response (DR): Electric customers who have a contract to modify their electricity usage in response to requests from a utility or other electric entity. Typically, will be used to lower demand during peak energy periods, but may be used to raise demand during periods of excess supply.

Direct Access: Large power consumers which have opted to procure their wholesale supply independently of the IOUs through an Electricity Service Provider.

EEI (Edison Electric Institute) Agreement: A commonly used enabling agreement for transacting in wholesale power markets.

Electric Service Providers (ESP): An alternative to traditional utilities. They provide electric services to retail customers in electricity markets that have opened their retail electricity markets to competition. In California the Direct Access program allows large electricity customers to opt-out of utility-supplied power in favor of ESP-provided power. However, there is a cap on the amount of Direct Access load permitted in the state.

Electric Tariffs: The rates and terms applied to customers by electric utilities. Typically have different tariffs for different classes of customers and possibly for different supply mixes.

Enterprise Model: When a City or County establish a CCA by themselves as an enterprise within the municipal government.

Federal Tax Incentives: There are two Federal tax incentive programs. The Investment Tax Credit (ITC) provides payments to solar generators. The Production Tax Credit (PTC) provides payments to wind generators.

Feed-in Tariff (FIT): A tariff that specifies what generators who are connected to the distribution system are paid.

Forward Prices: Prices for contracts that specify a future delivery date for a commodity or other security. There are active, liquid forward markets for electricity to be delivered at a number of Western electricity trading hubs, including NP15 which corresponds closely to the price location which the City of Davis will pay to supply its load.

Implied Heat Rate: A calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the 'break-even natural gas market heat rate,' because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices.

Integrated Resource Plan: A utility's plan for future generation supply needs.

Investor-Owned Utility (IOU): For profit regulated utilities. Within California there are three IOUs - Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric.

ISDA (International Swaps and Derivatives Association): Popular form of bilateral contract to facilitate wholesale electricity trading.

Joint Powers Agency (JPA): A legal entity comprising two or more public entities. The JPA provides a separation of financial and legal responsibility from its member entities.

Lancaster Choice Energy (LCE): A single-jurisdiction CCE serving residents of the City of Lancaster in Southern California. LCE launched service in October 2015 and served 51,000 customers.

LEAN Energy (Local Energy Aggregation Network): A not-for-profit organization dedicated to expanding Community Choice Aggregation nationwide.

Load Forecast: A forecast of expected load over some future time horizon. Short-term load forecasts are used to determine what supply sources are needed. Longer-term load forecasts are used for budgeting and long-term resource planning.

Marginal Unit: An additional unit of power generation to what is currently being produced. At and electric power plant, the cost to produce a marginal unit is used to determine the cost of increasing power generation at that source.

Marin Clean Energy (MCE): The first CCA in California now serving residents and businesses in the Counties of Marin and Napa, and the Cities of Richmond, Benicia, El Cerrito, San Pablo, Walnut Creek, and Lafayette.

Market Redesign and Technology Upgrade (MRTU): CAISO's redesigned, nodal (as opposed to zonal) market that went live in April of 2009.

Net Energy Metering (NEM): The program and rates that pertain to electricity customers who also generate electricity, typically from rooftop solar panels.

Non-bypassable Charges: Charges applied to all customers receiving service from Investor-Owned Utilities in California, but which are separated into a separate charge for departing load customers, such as Community Choice Aggregation and Direct Access Customers. These charges include charges for the Public Purpose Programs (PPP), Nuclear Decommissioning (ND), California Department of Water Resources Bond (CDWR), Power Charge Indifference Adjustment (PCIA), Energy Cost Recovery Amount (ECRA), Competition Transition Charge (CTC), Cost Allocation Mechanism (CAM).

Non-Coincident Peak: Energy demand by a customer during periods that do not coincide with maximum total system load.

Non-Renewable Power: Electricity generated from non-renewable sources or that does not come with a Renewable Energy Credit (REC).

NP15: Refers to a wholesale electricity pricing hub - North of Path 15 - which roughly corresponds to PG&E's service territory. Forward and Day-Ahead power contracts for Northern California typically provide for delivery at NP15. It is not a single location, but an aggregate based on the locations of all the generators in the region.

On-Bill Repayment (OBR): Allows electric customers to pay for financed improvements such as energy efficiency measures through monthly payments on their electricity bills.

Operate on the Margin: Operation of a business or resource at the limit of where it is profitable.

Opt-Out: Community Choice Aggregation is, by law, an opt-out program. Customers within the borders of a CCA are automatically enrolled within the CCA unless they proactively opt-out of the program.

Peninsula Clean Energy (PCE): Community Choice Aggregation program serving residents and businesses of San Mateo County. PCE launched in October of 2016.

Power Cost Indifference Adjustment (PCIA): A charge applied to customers who leave IOU service to become Direct Access or CCA customers. The charge is meant to compensate the IOU for costs that it has previously incurred to serve those customers.

Power Purchase Agreement (PPA): The standard term for bilateral supply contracts in the electricity industry.

Renewable Energy Credits (RECs): The renewable attributes from RPS-qualified resources which must be registered and retired to comply with RPS standards.

Resource Adequacy (RA): The requirement that a Load-Serving Entity own or procure sufficient generating capacity to meet its peak load plus a contingency amount (15 percent in California) for each month.

Renewable Portfolio Standard (RPS): The state-based requirement to procure a certain percentage of load from RPS-certified renewable resources.

Scheduling Coordinator: An entity that is approved to interact directly with CAISO to schedule load and generation. All CAISO participants must be or have an SC.

Scheduling Agent: A person or service that forecasts and monitors short term system load requirements and meets these demands by scheduling power resource to meet that demand.

Silicon Valley Clean Energy (SVCE): CCA serving customers in twelve communities within Santa Clara County including the cities of Campbell, Cupertino, Gilroy, Los Altos, Los Altos Hills, Los Gatos, Monte Sereno, Morgan Hill, Mountain View, Saratoga, Sunnyvale, and the County of Santa Clara. As of the date of completion of this study, SVCE had not yet launched service.

Sonoma Clean Power (SCP): A CCA serving Sonoma County and Sonoma County cities. On December 29th, SCP received approval of their implementation plan from the California Public Utilities Commission to extend service into Mendocino County.

Spark Spread: The theoretical grow margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity. All other costs (capital, operation and maintenance, etc.) must be covered from the spark spread.

Supply Stack: Refers to the generators within a region, stacked up according to their marginal cost to supply energy. Renewables are on the bottom of the stack and peaking gas generators on the top. Used to provide insights into how the price of electricity is likely to change as the load changes.

Inland Choice Power (ICP): Refers collectively to the three councils of governments: Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG), and Western Riverside Council of Governments (WRCOG).

Weather Adjusted: Normalizing energy use data based on differences in the weather during the time of use. For instance, energy use is expected to be higher on extremely hot days when air

conditioning is in higher demand than on days with comfortable temperature. Weather adjustment normalizes for this variation.

Western Electric Coordinating Council (WECC): The organization responsible for coordinating planning and operation on the Western electric grid.

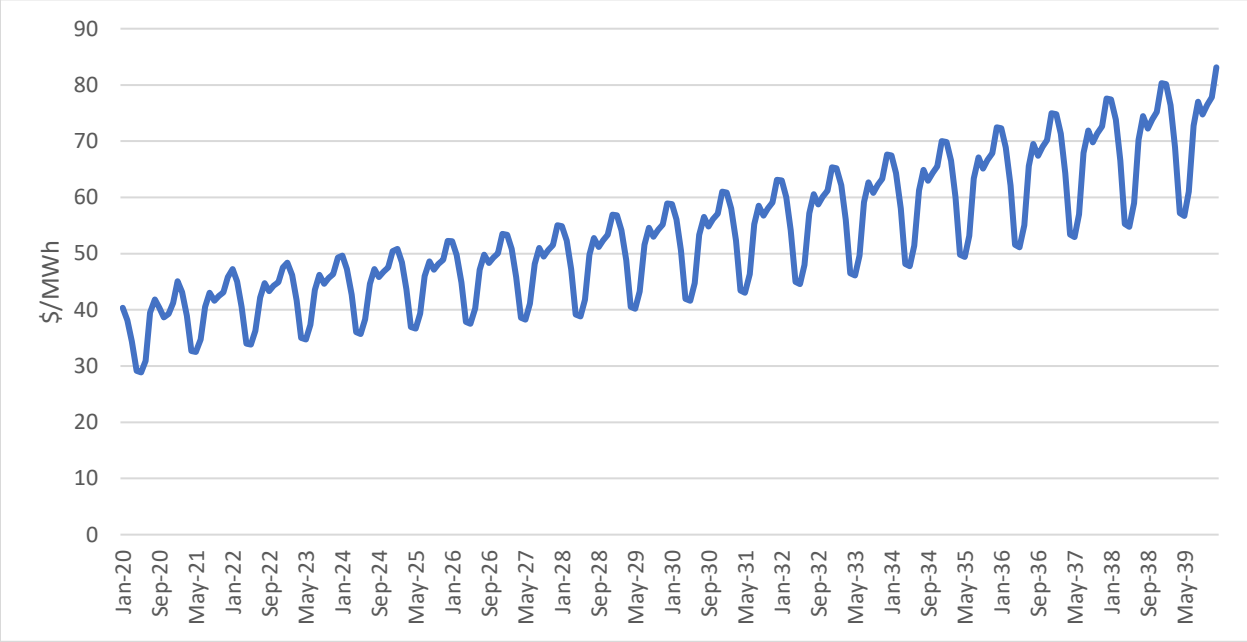
Wholesale Power: Large amounts of electricity that are bought and sold by utilities and other electric companies in bulk at specific trading hubs. Quantities are measured in MWs, and a standard wholesale contract is for 25 MW for a month during heavy-load or peak hours (7am to 10 pm, Mon-Sat), or light-load or off-peak hours (all the other hours).

Western States Power Pool (WSPP) Agreement: Common, standardized enabling agreement to transact in the wholesale power markets.

Wholesale Market Prices

Market prices for NP15 were provided by EES Consulting's subscription to a market price forecasting service.[48] An adder of $2/MWh was included in the forecast PPA prices to account for potential price differences between NP15 and the pricing nodes at which the CCA will transact. An additional adder of $1/MWh was included for a bid/ask spread. Exhibit F-1 below shows forecast monthly northern California wholesale electric market prices. The levelized value of market prices over the 20-year study period is $49.1/MWh (2018$) assuming a 4 percent discount rate. Electric market prices peak in the winter and summer when there is large heating and cooling load.

Exhibit F-1
Forecast Northern California Wholesale Market Prices



Wholesale power prices have been used to calculate balancing market purchases and sales. When the CCA's loads are greater than its resource capabilities, the CCA's scheduling coordinator will schedule balancing purchases and the CCA will incur balancing market purchase costs. When the CCA's loads are less than its resource capabilities, the CCA's scheduling coordinator will transact balancing sales and the CCA will receive market sales revenue. Balancing market purchases and sales can be transacted on a monthly, daily and hourly pre-schedule basis.

[48] Market Intelligence. Prices current as of July 9, 2018.

Ancillary and Congestion Costs

The CCA will pay the CAISO for transmission congestion and ancillary services. Transmission congestion occurs when there is insufficient capacity to meet the demands of all transmission customers. Congestion refers to a shortage of transmission capacity to supply a waiting market, and is marked by systems running at full capacity and still being unable to serve the needs of all customers. The transmission system is not allowed to run above its rated capacities. Congestion is managed by the CAISO by charging congestion charges in the day-ahead market. Congestion charges can be managed through the use of Congestion Revenue Rights (CRR). CRRs are financial instruments made available through a CRR allocation, a CRR auction, and a secondary registration system. CRR holders manage variability in congestion costs. The CCA's congestion charges will depend on the transmission paths used to bring resources to load. As such, the location of generating resources used to serve Butte County CCA load will impact these congestion costs.

The Grid Management Charge (GMC) is the vehicle through which the CAISO recovers its administrative and capital costs from the entities that utilize the CAISO's services. Based on a survey of GMC costs currently paid by CAISO participants, the CCA's GMC costs are expected to be near $0.5/MWh.

The CAISO performs annual studies to identify the minimum local resource capacity required in each local area to meet established reliability criteria. Load serving entities receive a proportional allocation of the minimum required local resource capacity by transmission access charge area, and submit resource adequacy plans to show that they have procured the necessary capacity. Depending on these results of the annual studies, there may be costs associated with local capacity requirements for the CCA.

Because generation is delivered as it is produced and, particularly with respect to renewables can be intermittent, deliveries need to be firmed using ancillary services to meet the CCA's load requirements. Ancillary services will need to be purchased from the CAISO. Regulation and operating reserves are described below.

- *Regulation Service:* Regulation service is necessary to provide for the continuous balancing of resources with load and for maintaining scheduled interconnection frequency at 60 cycles per second (60 Hertz). Regulation and frequency response service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load.

- *Operating Reserves - Spinning Reserve Service:* Spinning reserve service is needed to serve load immediately in the event of a system contingency. Spinning reserve service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service.

- *Operating Reserves – Non-Spinning Reserve Service:* Non-spinning reserve service is available within a short period of time to serve load in the event of a system contingency. Non-spinning reserve service may be provided by generating units that are on-line but not providing power, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service.

Based on a survey of ancillary service costs currently paid by CAISO participants, the CCA's ancillary service costs are estimated to be near $1.5/MWh. The Plan's base case will assume the CCA's ancillary service costs are $1.5/MWh in 2020, escalating by 1.5 percent annually thereafter. Serving a greater percentage of load with renewables will likely result in increased grid congestion and higher ancillary service costs. For this reason, the ancillary service costs have been increased up to $2.5/MWh in the 75% Renewables portfolio (plus 1.5 percent annual escalation). The scenarios included in this Plan as shown below in Exhibit F-2.

Exhibit F-2
Base Case Ancillary Service Costs in Resource Portfolios

Portfolio	2020 Ancillary Service Costs	Annual Escalation Factor
1- Meet RPS Targets	1.5	1.5%
2- Serve 50% of Retail Load with Renewables	2.0	1.5%
3- Serve 75% of Retail Load with Renewables	2.5	1.5%

Scheduling Coordinator Services

A scheduling coordinator provides day-ahead and real-time power and transmission scheduling services. Scheduling coordinators bear the responsibility for accurate and timely load forecasting and resource scheduling including wholesale power purchases and sales required to maintain hourly load/resource balances. A scheduling coordinator needs to provide the marketing expertise and analytical tools required to optimally dispatch the CCA's surplus and deficit resources on a monthly, daily and hourly basis.

Inside each hour, the CAISO Energy Imbalance Market (EIM) takes over load/resource balancing duties. The EIM automatically balances loads and resources every fifteen minutes and dispatches least-cost resources every 5-minutes. The EIM allows balancing authorities to share reserves, and more reliably and efficiently integrate renewable resources across a larger geographic region.

Within a given hour, metered energy (i.e., actual usage) may differ from supplied power due to hourly variations in resource output or unexpected load deviations. Deviations between metered energy and supplied power are accounted for by the EIM. The imbalance market is used to resolve imbalances between supply and demand. The EIM deals only with energy, not ancillary services or reserves.

The EIM optimally dispatches participating resources to maintain load/resource balance in real-time. The EIM uses the CAISO's real-time market, which uses Security Constrained Economic Dispatch (SCED). SCED finds the lowest cost generation to serve the load taking into account operational constraints such as limits on generators or transmission facilities. The five-minute market automatically procures generation needed to meet future imbalances. The purpose of the five-minute market is to meet the very short-term load forecast. Dispatch instructions are effectuated through the Automated Dispatch System (ADS).

The CAISO is the market operator, and runs and settles EIM transactions. The CCA's scheduling coordinator will submit the CCA's load and resource information to the market operator. EIM processes are running continuously for every fifteen-minute and five-minute intervals, producing dispatch instructions and prices.

Participating resource scheduling coordinators submit energy bids to let the market operator know that they are available to participate in the real-time market to help resolve energy imbalances. Resource schedulers may also submit an energy bid to declare that resources will increase or decrease generation if a certain price is struck. An energy bid is comprised of a megawatt value and a price. For every increase in megawatt level, the settlement price also increases.

The CAISO calculates financial settlements based on the difference between schedules and actual meter data, and bid prices during each hour. Locational Marginal Prices (LMP) are used in settlement calculations. The LMP is the price of a unit of energy at a particular location at a given time. LMPs are influenced by nearby generation, load level, and transmission constraints and losses.