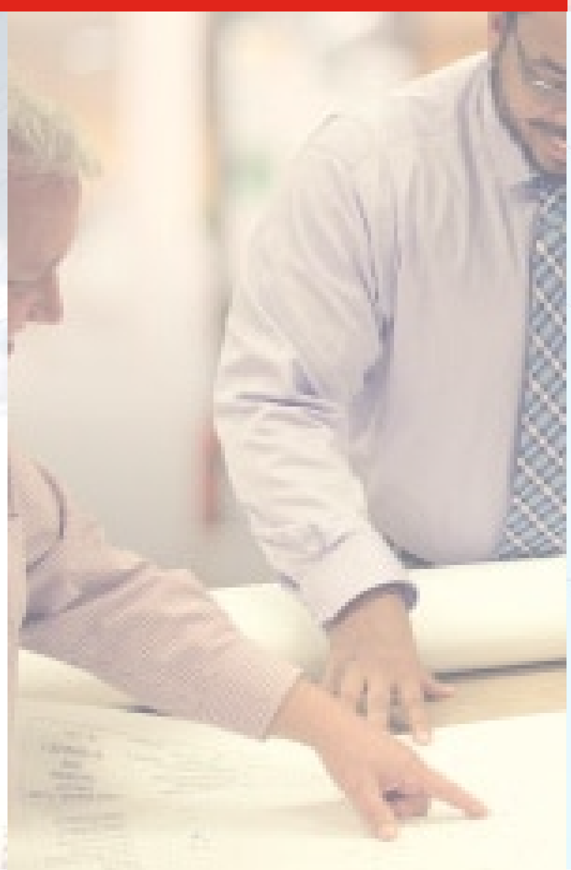
PREPARED BY EES CONSULTING

Community Choice Aggregation Technical Feasibility Study

Prepared for the Cities of Escondido, San Marcos, and Vista

May 24, 2021



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May 24, 2021

Mr. John Conley
Community Development Director
City of Vista
200 Civic Center Drive
Vista, CA 92084

SUBJECT: CCA Technical Feasibility Study

Dear Mr. Conley:

Please find attached the Community Choice Aggregation (CCA) Technical Feasibility Study (Study) for the cities of Escondido, San Marcos, and Vista.

We very much appreciate all the effort your project team has spent on the Study, and we hope this report is useful as the Cities evaluate CCA program implementation.

Very truly yours,

Gary Saleba
EXECUTIVE CONSULTANT

TABLE OF CONTENTS

1 Executive Summary

Since the State's first Community Choice Aggregation (CCA program was launched in Marin County in 2010, many communities across the state have benefitted from reduced electricity costs and community-specific activities and programs associated with CCA operations. To date, 23 CCAs comprising multiple counties and cities are operating; and even more are scheduled to commence operations in 2021 and 2022.

Under the CCA business model, local governments purchase and manage their community's electric power supply by sourcing power from a preferred mix of traditional and renewable energy sources, while the incumbent investor-owned utility (IOU), in this case San Diego Gas and Electric (SDG&E), continues to provide distribution and billing service.

To better understand the benefits and risks associated with CCA programs, the cities of Escondido, San Marcos, and Vista (VSME Partners) selected EES Consulting (EES) to prepare this Study that assesses the technical feasibility of CCA operations as a mechanism to provide choice to customers, lower their electricity rates, and contribute toward achieving the VSME Partners' Climate Action Plan (CAP) targets for greenhouse gas reduction. CAP goals for each VSME City are summarized below.

- The City of Vista will join a program (e.g., CCA) to increase the renewable or zero-carbon electricity supplied to the city to 90%, reducing citywide emissions by approximately 28,300 MTCO2e in 2030.[1]
- The City of San Marcos intends achieve 95% zero carbon electricity by 2030 for a reduction of 34,336 $MTCO_2$.[2]
- The City of Escondido intends to reduce GHG emissions through energy efficiency and renewable energy choice (100% renewable energy by 2030).[3] Both of these measures could be promoted through CCA.

This Study evaluates the technical (economic) feasibility of a VSME Partner CCA as well as for each VSME City individually. The study does not assume that the cities will enter into joint decision-making based on the results. Each VSME City can choose to remain with bundled service through SDG&E, form its own city-only CCA, participate in the creation of a new CCA, or join an existing CCA.

[1] Measure E-4 Page ES-5 City of Vista Climate Action Plan. October 2019. Available at: https://www.cityofvista.com/Home/ShowDocument?id=20634

[2] City of San Marcos Climate Action Plan. December 14, 2020. Available at: https://www.san-marcos.net/departments/development-services/planning/climate-action-plan

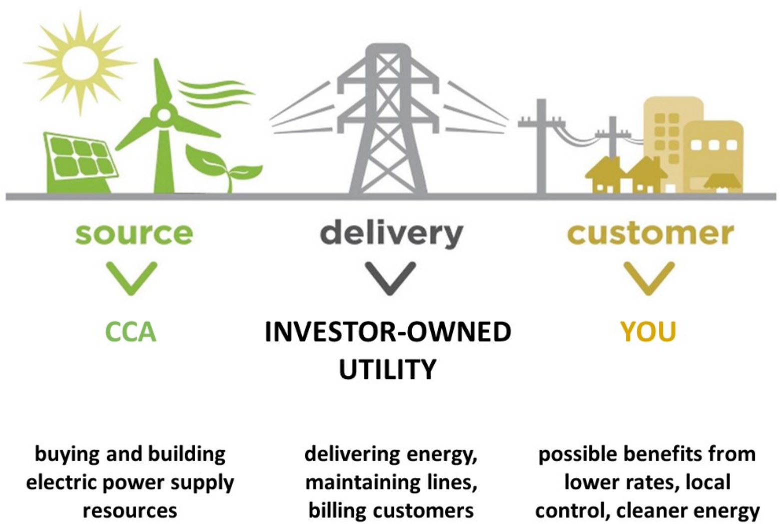
[3] City of Escondido Climate Action Plan. Page 3-17. Available at : https://www.escondido.org/Data/Sites/1/media/PDFs/Planning/ClimateActionPlan/Final/ResolutionExAEscondidoCAP3GHGReduction_FINAL3.pdf

1.1 BACKGROUND ON CCA BUSINESS MODEL

California Assembly Bill 117 allows local governments to form CCAs that offer an alternative electric power supply option to constituents currently served by IOUs. CCAs face the same requirements for renewable energy purchases as the incumbent IOUs and other public utilities; however, many CCA programs can offer power content that has a greater share of renewable energy compared with the incumbent utility and at lower retail rates.

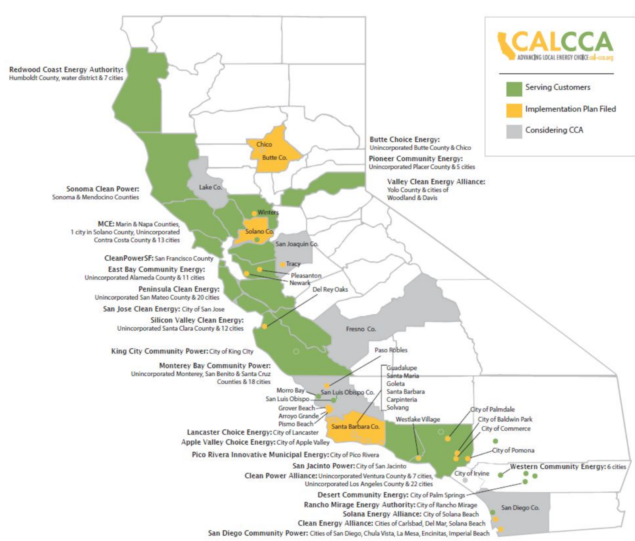
Figure 1-1 illustrates how CCAs function within the traditional electric utility industry supply infrastructure.

FIGURE 1-1. CCA BUSINESS MODEL CONSTRUCT



As illustrated in Figure 1-2 below, there are currently 23 operational CCAs in the state, serving more than 11 million customers.

FIGURE 1-2. CCA LOCATIONS



The 23 operational CCAs vary widely in size and governance structure. Table 1-1 summarizes the existing CCAs relative size on internal governance structures. The Hybrid governance refers to an enterprise CCA where administration costs are shared with other CCAs through a JPA. For comparison, the VSME Partner estimated participating load is 1,600 GWh.

TABLE 1-1. CCA PROGRAM SIZE AND OPERATIONAL STRUCTURE

CCA Name	2021 GWh Load	Service Location	Operational Structure	Inception Date
Clean Power Alliance	11,113	SCE	JPA	2018
San Diego Community Power[1]	7,407	SDG&E	JPA	2021
East Bay Community Energy	5,951	PG&E	JPA	2018
MCE	5,879	PG&E	JPA	2010
Central Coast Community Energy	4,507	PG&E and SCE	JPA	2018
San Jose Clean Energy	4,462	PG&E	Enterprise	2018
Silicon Valley Clean Energy	3,991	PG&E	JPA	2017
Orange County Power Authority	3,692	SCE	JPA	2022
Peninsula Clean Energy	3,290	PG&E	JPA	2016
CleanPowerSF	3,083	PG&E	Enterprise	2016
Sonoma Clean Power	2,335	PG&E	JPA	2014
Western Community Energy	1,575	SCE	JPA	2020
Desert Community Energy	1,433	SCE	JPA	2020
Pioneer Community Energy	1,187	PG&E	JPA	2018
Butte Choice Energy Authority	1,123	PG&E	JPA	2023
Clean Energy Alliance[1]	929	SDG&E	JPA	2021
Valley Clean Energy	737	PG&E	JPA	2018
Redwood Coast Energy Authority	631	PG&E	JPA	2017
Lancaster Choice Energy	551	SCE	Hybrid	2015
Pomona Choice Energy	409	SCE	Hybrid	2020
Rancho Mirage Energy Authority	266	SCE	Hybrid	2018
Pico Rivera Innovative Municipal Energy	243	SCE	Hybrid	2017
Baldwin Park	241	SCE	Hybrid	2020
Apple Valley Choice Energy	235	SCE	Hybrid	2017
San Jacinto Power	160	SCE	Hybrid	2018
Solana Energy Alliance[2]	60	SDG&E	Enterprise	2018
King City Community Power	34	PG&E	Enterprise	2018

1. Load is forecast 2022 after all currently scheduled enrollments are completed
2. Part of CEA beginning in 2021

It should be noted that the CCA business model was first applied in Marin County roughly 10 years ago by establishing Marin Clean Energy. Since this first CCA formation, another 23 have been launched. All of these CCAs have operated successfully. As indicated above, at least 2 additional CCAs are planning to launch in 2022 and 2023.

Other potential partnerships exist in the San Diego region as three other jurisdictions continue to evaluate CCA programs including the City of Santee, City of Oceanside, and County of San Diego. At the time of this study, these entities have not yet established a clear path for either joining an existing CCA or establishing a new program.

1.2 OVERVIEW OF STUDY PURPOSE AND ANALYTICAL CONSTRUCT

The purpose of this study is to: estimate all CCA operating costs (including power supply, labor, consultants, regulatory, legal, financing), calculate anticipated CCA revenues by projecting customer rates, determine if projected revenues can cover estimated operating costs and whether projected CCA rates are comparable to or lower than projected SDG&E rates. The Study's power supply options are consistent with the VSME Partner Climate Action Plan (CAP) goals to achieve up to 100% renewable electricity by 2030.[4] Risks are assessed through a sensitivity analysis on key input variables. The Study also looks at various governance options.

In order to determine the technical and financial feasibility of a CCA in the participating cities' service territory (VSME Partner CCA), a comparison of SDG&E rates versus corresponding rates for a Partner CCA must be undertaken. If a VSME Partner CCA can provide electricity at a lower price than SDG&E, the CCA business model is deemed to be technically and financially feasible. Within this Study, a forecast of SDG&E and VSME Partner CCA rates is performed. The details of this comparison are provided within this Study. This Executive Summary contains the highlights of the Study. The balance of this Study discusses the details of this rate comparison, then continues to discuss a VSME Partner CCA's environmental, economic, governance and operational relative attributes. A glossary of terms and acronyms is available in Appendix D at the end of this Study.

1.3 STUDY ASSUMPTIONS AND SCENARIOS

Electrical usage data for all residences and businesses located within the Cities' incorporated areas was provided by SDG&E. Figures 1-3 and 1-4 show the forecast energy consumption by electric accounts in the incorporated areas. Residential, commercial and industrial customers make up the majority of energy use. Street lighting and agricultural use make up the balance of energy use with the latter stemming primarily from irrigation load.

[4] Individual city goals are Vista: 90% by 2030, San Marcos: 95% by 2030, and Escondido: 100% GHG free by 2030.

FIGURE 1-3. FORECAST CCA SERVICE AREA LOAD

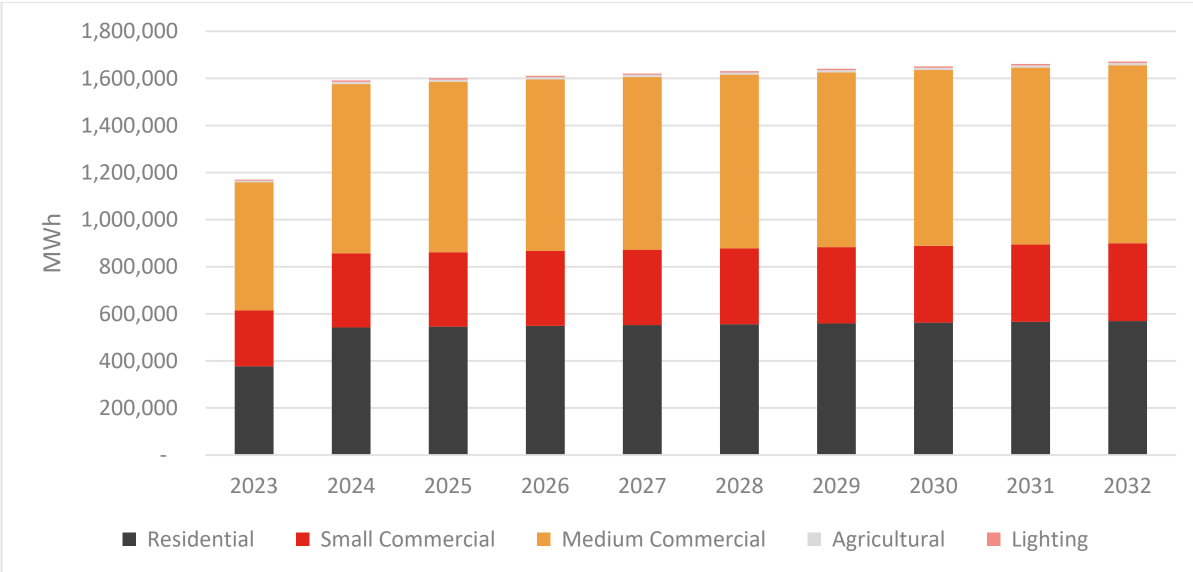
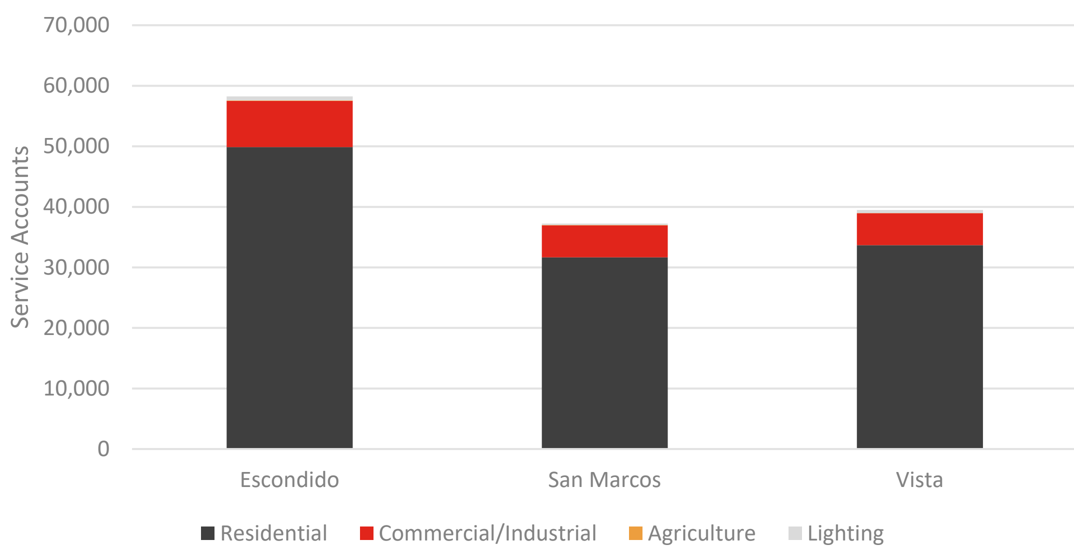


FIGURE 1-4. 2023 FORECAST SERVICE ACCOUNTS



Electricity can be produced in several ways. In California, electricity was historically produced using nuclear, natural gas, coal and hydro resources. More recently, renewable resources, such as solar, wind, and geothermal have increasingly been used to generate electricity. These renewable resources and power provided from hydrologic facilities are also greenhouse gas (GHG) free. These attributes are considered in the CCA power portfolio analysis in this study.

At this time, SDG&E's standard power supply offering is 44% from renewable resources. In California, most renewable energy comes from solar and wind generation. SB 100, adopted in 2018, accelerates the State-mandated Renewable Portfolio Standard (RPS) obligations as follows:

- 44% from renewable sources by 2024
- 52% from renewable sources by 2027
- 60% from renewable sources by 2030
- 100% GHG free electricity by 2045

While a high-level analysis of all CCA governance options are evaluated here, the Study's base-line calculations assume the Cities will proceed with a VSME Partner CCA operating as a standalone entity. As described in further detail in the Governance section of this report, this option is commonly called the Enterprise CCA business model. The Study also assumes that the VSME Partner CCA would purchase power supply options in compliance with the cities' CAP measure to achieve 90-100% renewable energy(or GHG free energy) by 2030. This level of renewable energy will exceed SB 100's 2030 targets of 60% renewable. The VSME Partner CCA will also meet SB 350 requirements requiring 65% of renewable energy be met by long-term (10 or more years) power supply contracts and comply with all other related California Public Utility Commission (CPUC) regulations. The Study compares VSME Partner CCA rates to forecasted SDG&E rates. All rate discounts or bill savings referenced throughout the Study are the savings off the total SDG&E rate which includes energy supply, transmission, distribution, and other charges.

To provide information about cost differences among renewable resource portfolios, this Study analyzes three power supply scenarios detailed in Table 1-2 for the VSME Partner CCA option. Additional portfolios are specifically analyzed for individual city CCA feasibility.

TABLE 1-2. VSME PARTNER CCA RESOURCE PORTFOLIOS

	% Renewable[1] at Launch (2023)	% Renewable in 2030
Scenario 1: 60% Renewable (RPS Compliant) Portfolio	41%	60%
Scenario 2: 90% Renewable by 2030 (Base Case) Portfolio	75%	90%
Scenario 3: 100% Renewable Portfolio	100%	100%

[1]Renewable includes only RPS eligible resources. For this study, all eligible renewable resources are also greenhouse gas (GHG) free. Where renewables don't meet the CPUC's GHG free definition, GHG free attributes are purchased through a $/MWh adder.

It is assumed throughout this Study that Scenario 2 is the "base case". Scenario 2 is also consistent with the City of Vista's 90% renewable by 2030 CAP goal. Scenario 3 would meet or exceed CAP goals for both San Marcos and Escondido. The results later show that portfolio choice between 90% and 100% renewable does not significantly impact the financial feasibility.

1.4 KEY FINDINGS

The Study results show that a VSME Partner CCA is financially feasible and can provide the following benefits:

- Each VSME City could establish its own technically and financially sound CCA program and have local control of its own power supply. Each VSME City's respective CAP goal for GHG free or renewable power supply can be met under current market conditions while providing an estimated 2% rate discount when compared with SDG&E bundled rates.

- Establishing a VSME Partner CCA reduces start-up costs compared with each VSME City establishing its own program and provide economy of scale savings. CCA start-up costs are estimated at $600,000 for each program. Additionally, the VSME Partner CCA will need roughly $18M in cash working capital, collateral, and start-up costs. Most of this is assumed to be financed externally. Both the initial start-up costs and cash working capital loans are forecasted to be fully repaid within the first five years of the VSME Partner CCA operations.

- Under Scenarios 2 and 3, which are consistent with the VSME City CAP goals,, CCA customer bills are predicted to be 2% lower than forecasted SDG&E total bills for the first 5-years of CCA operation.

- Under a VSME Partner CCA Program, electricity cost savings are estimated at $9.3 million per year over the next ten years for residents and businesses located within the Cities.

- In order to assess the risks associated with operating a CCA, the Study analyzed CCA rate results under scenarios with high and low participation rates, high and low market power supply costs, and high and low SDG&E departing load charges (Power Charge Indifference Adjustment, PCIA). The findings identify key risks with regard to stranded cost recovery and power supply costs. The Study's section on Risks and Sensitivity Analysis describes the magnitude of those risks and measures for mitigating those risks. There are some, scenarios where the CCA costs exceed the headroom available between SDG&E generation rates and the exit fees charged by SDG&E to CCA customers.

- The VSME Partner CCA will have a 10-year average annual surplus revenue stream of $15.5 million ($1.6 M/year). After financial reserves are collected, $14 million of this revenue stream can be used for customer-related programs such as:
  - Energy efficiency programs.
  - Local renewable energy resource programs, such as renewable energy generation and net metering.
  - Rate savings are estimated at 2% of total electric bills, or 4.5% savings off generation rates.
  - The VSME Partner CCA could trade off energy program funding for rate savings or vice versa.

- The Study uses an economic input/output model (IMPLAN) to estimate the economic impacts of CCA-related rate savings. The rate savings to customers under the VSME Partner CCA would additionally result in local economic development benefits, such as 113 new jobs and a total of $9.3 million in additional annual economic output.

- If the VSME Partner CCA would have full control over its power supply purchases and could create a power supply mix that meets each of the cities CAP goals. The cost for power supply can be allocated to each city/rate product to recover costs fairly and equitably.

Table 1-3 shows Key Operating Figures for a VSME Partner CCA and the three individual Enterprise CCAs (each VSME City establishes its own program).

TABLE 1-3. VSME PARTNER CCA KEY OPERATING FIGURES

Power Supply Portfolio Scenario:	VSME Partner CCA : 90% Renewable Portfolio	City of Vista Enterprise CCA: 90% Renewable Portfolio	City of San Marcos Enterprise CCA: 95% Renewable Portfolio	City of Escondido Enterprise CCA:100% Renewable Portfolio
2024 Operating Budget, $ million	$105	$31	$31	$46
2024 Revenues, $ million	$118	$32	$32	$50
2024 Load Served, GWh	1,527	484	431	666
Startup Loan (Including Pre-Startup Costs and Working Capital, Collateral), $ million	$18	$9	$9	$9
Startup Loan and repayment, years	5	5	5	5
Average Rate Discount, %	2.1%	2.0%	2.0%	2.0%

1.5 GOVERNANCE

The following portion of the executive summary is an introduction to the governance component of the Business Plan focusing on governance options.

If the cities choose to implement a CCA, they each must select an appropriate governance structure. This Study evaluated the following four governance options:

- Enterprise CCA – Each of the VSME Cities operates its own CCA as a city department. Under this option there could be multiple organizational structures. For example, the enterprise CCAs could join together or with other individual CCAs under a JPA for sharing certain CCA operating costs and services. Administration costs are shared but power supply mix, rates, and potentially other programs are unique to each member CCA.
- Partner Joint Powers Authority (JPA) CCA – The VSME Cities partner together or with other public agencies to form a single CCA governed under a JPA. Additional potential partners may include the City of Oceanside, Unincorporated County of San Diego, City of Santee, or others. As of this writing, none of the cities have committed to a partner, or have submitted an Implementation Plan to the CPUC; however, the named potential partners are all jurisdictions who have analyzed CCA through their own feasibility studies.
- Joining Existing JPA in or outside SDG&E Service Area
    - San Diego Community Power – JPA consisting of the Cities of San Diego, Encinitas, Chula Vista, La Mesa, and Imperial Beach. This program is scheduled to launch in 2021 and will be the largest CCA in the SDG&E service area.
    - Clean Energy Alliance – JPA consisting of the Cities of Carlsbad, Del Mar, and Solana Beach. This new CCA will launch in 2021 and will include customers currently served by Solana Energy Alliance (SEA) a currently operating CCA in San Diego County.
    - CCA outside SDG&E Service Area – Other potential partners include jurisdictions in other IOU service areas. Central Coast Community Energy will be the first CCA to serve customers across 2 IOU service areas in 2021. Other operating JPAs may be interests in expanding to the SDG&E service area as well including the newly formed Orange County Power Authority.

A summary of key findings for each governance option is provided in Table 1-4. If the cities were to join an existing JPA, there will likely be a cost to join. The specific costs would be unique for each situation and are not provided below.

TABLE 1-4. GOVERNANCE OPTIONS SUMMARY

	Enterprise CCA	Three City JPA CCA
Pre-Launch Costs	$600,000 each City	<=$600,000 Total
Start-Up Costs, Working Capital, and Collateral (Financed)	Escondido: $9 million San Marcos: $9 million Vista: $9 million	$18 million
Estimated Bundled Rate Discount	2%	At least 2%
Probable Launch Date	2023	2023
Power Supply Cost Allocation and Program Customization	Individual	Shared or Individual

The Pre-launch Costs estimated at $607,000 million are detailed in Table 1-5 for a launch date of April 2023. These pre-launch costs for start-up are the minimum funds needed to launch a CCA program. These costs assume deferred consultant costs until launch and member city staff support rather than hiring program staff. CCAs that hire program staff immediately typically spend between $1.5 and $2.5 million in the year prior to launch.

TABLE 1-5. START-UP COST ESTIMATES

CPUC Bond	$147,000
SDG&E Fees	$10,000
Staffing	$150,000
Consultants	$300,000
Total	**$607,000**

Enterprise CCA – A city-only Enterprise CCA retains the greatest amount of local control for programs, organization, and power supply. Surplus revenues above what is needed to run the CCA program remain under the cities' direct control. Power supply choice, rate discounts, customer program designs, marketing, and outreach are customized to the Cities' needs. The Enterprise CCA option is well suited for jurisdictions that are large enough to operate individually and may not find partners with similar goals and demographics. The City of San Jose, for instance, set up an Enterprise CCA that is functioning smoothly. Various mechanisms are available to shield the general fund from liability associated with an Enterprise CCA, including fund segregation, contractual protections, and insurance, which can be addressed in more detail by the Cities' Counsel and staff. This option also requires the Cities to secure or provide the $600,000 in pre-launch funding. . A CCA's working capital is typically financed externally, and options for financing the pre-launch costs are also available.

Once an Enterprise CCA is formed, it could then partner with other cities to form a JPA to share overhead costs (Enterprise JPA). Under this type of JPA, each member is its own CCA and chooses its own power supply portfolio, retail rate design, customer program development, CCA branding, and CCA marketing and outreach. Some administration costs can be shared in this model, such as power supply procurement, scheduling and dispatch, data management, integrated resource planning, regulatory services, and customer programs development and implementation. The Enterprise JPA model is made up of individual CCAs; therefore, contracts for the services just described are entered into by each CCA either directly with each service provider or through the JPA. For example, a three-member JPA would have a single contract manager administering three separate power contracts—one for each CCA—as opposed to three individual contract managers each administering a single contract. This structure allows for the sharing of some overheads.

VSME Partner JPA CCA – The cities could form a CCA with other jurisdictions under a JPA. This would include jurisdictions in the region that do not want to pursue their own CCA or join the other existing CCAs. Under this option, the governing body of each member would pass an ordinance to approve joining a VSME Partner-developed JPA CCA. The JPA operates as its own entity and typically is governed by a Board consisting of one elected official from each member jurisdiction. Voting requirements would be documented in the JPA agreement. Under a VSME Partner JPA, the CCA would have a larger customer base, and could possibly offer higher rate discounts compared with individual CCAs for each city. The start-up costs would typically be shared among the JPA members and each member would pay a prorated portion of the startup costs. Under this scenario, the VSME Partner JPA would need to secure the start-up funding. The working capital financing would be shared by all members. The power supply mix for a VSME Partner JPA would be determined by the Board of Directors and the default power supply option for each VSME City could be selected independently to meet individual VSME City CAP goals.

San Diego Community Power (SDCP) – As noted above, SDCP currently consists of the cities of San Diego, Encinitas, Chula Vista, La Mesa, and Imperial Beach. As the largest SDG&E CCA, SDCP may provide economies of scale savings resulting in additional rate savings depending on how SDCP sets its internal goals. These scale savings would occur through overhead costs and potentially through power supply contracts.

While participation in SDCP may have additional economies of scale benefits, there would be a trade-off in the level of control for each city. Careful consideration would need to be given to the JPA agreement regarding the guarantee of new program funding for each JPA member. Other considerations should also be analyzed in terms of jurisdictional voting, potential weighted voting, and overall program goals.

Joining an existing JPA will likely require the cities to produce some upfront funding. The amount and terms of this funding would need to be acquired through formal request for proposal or information process.

Clean Energy Alliance (CEA) – Similarly the cities could join CEA—an existing JPA—and launch in either 2022 or 2023. CEA is a much smaller CCA compared with SDCP, but it may still offer economies of scale savings. As with SDCP, the VSME Cities should carefully consider joining costs, voting structure, and program goals to determine if CEA is a good fit.

Joining Existing JPA in or outside SDG&E Service Area – Finally, the VSME Cities could join an existing CCA operating in either PG&E or SCE service area. In order to gauge potential partnerships, the Cities could issue a request for information to various operating CCAs to determine the costs and structure of a potential agreement. There are benefits of joining a well-established CCA since operating and rate stabilization reserves are likely to have been established. Whereas, joining a new CCA (<1 year in operation) would carry similar risks as starting a new CCA.

1.6 RISKS

While the Study shows that forming a CCA is technically feasible under a wide range of scenarios, doing so is not without risk. The feasibility of a VSME Partner CCA (maintaining customer rates competitive with SDG&E and maintaining positive net revenues), primarily depends on power supply costs, which make up over 90% of the overall CCA operating budget. Other factors impacting the financial feasibility of the CCA include: costs SDG&E directly passes through to all customers (including the Power Charge Indifference Adjustment or PCIA), market supply of renewable power, availability and cost of financing CCA operations, and legislative and regulatory actions.

To assess the magnitude of risk imposed on a potential CCA program by these factors, the Study includes a Sensitivity and Risk Analysis section. This section establishes a wide range of high and low scenarios of prices for CCA-procured market power, SDG&E's forecasted customer rates, CCA financing costs, CCA's customer participation rates, and the level of SDG&E's PCIA.

The results of the Sensitivity and Risk Analysis indicate under what scenarios the CCA's rates may exceed SDG&E's customer rates, and also suggest actions the CCA can take to manage these risks. The risk mitigation actions consist of standard industry best practices and strategies employed by other established CCAs—including conservative power procurement strategies, utilization of market risk management policies, development of a cash reserve fund from annual net revenues, and engagement with State regulatory and legislative issues.

1.7 CONCLUSIONS

The Study results suggest that CCA programs are technically and financially feasible for the cities whether each VSME City forms its own program or they join together to form a VSME Partner CCA. These findings are based on the mentioned governance options and under current market conditions. The economies of scale for all options are sufficient for stable CCA operation under a wide range of financial assumptions and sensitivities.

Suggested next steps for the VSME Partners include completing an internal review of this Study, receiving the Study results through City Council action, and determining whether to move forward with further evaluation of a CCA. If the policy decision is to proceed with establishing a CCA, the VSME Partners should decide which governance option they prefer, begin pre-startup operations required to launch the CCA, and file an Implementation Plan with the CPUC on a timely basis.

2 Introduction

Since the State's first CCA program was launched in Marin County in 2010, many communities across the state have benefitted from reduced electricity costs and community-specific activities and programs associated with CCA operations. To date, 23 CCAs comprising multiple counties, cities, and towns are operating with more territory expansions schedule for 2021 and 2022.

To better understand the benefits and risks associated with CCA programs, the cities of Escondido, San Marcos, and Vista (VSME Partners) selected EES Consulting (EES) to prepare this Study that assesses the technical feasibility of CCA operations as a mechanism to provide choice to customers, lower their electricity rates, and contribute toward achieving the VSME Cities' various Climate Action Plan (CAP) goals for greenhouse gas (GHG) reduction and renewable energy portfolios. This Study examines the technical and financial viability of a CCA program that serves customers in the VSME Partner cities. Upon the finding that a CCA business model is technically feasible, a business plan for VSME Partner CCA is to be developed to assess risks, governance options, and environmental and macroeconomic impacts.

2.1 HISTORY OF CCA IN CALIFORNIA

AB 117 was enacted in 2002 and became law the same year. This legislation enables jurisdictions, such as cities and counties, to implement electric power supply programs that offer electric consumer choice. The entities given this authority are known as Community Choice Aggregators (CCAs). The programs implemented by these CCAs were designed to be opt-out programs where customers are automatically enrolled after notification but can opt-out if desired. Marin Clean Energy (MCE) implemented the first CCA program in 2010.

As the first CCA program to serve customers in California, MCE has worked to establish CCA-common practices by offering 50% to 100% renewable energy choices to its customers. MCE has contracted with a variety of power suppliers of new renewable projects including landfill gas and several local solar power projects. MCE incentivized local project development through both its feed-in-tariff rates and direct investment.

2.2 CCA PROGRAMS AND STATUS OF PENDING CCAS

Table 2-1 summarizes the current status of CCAs operating in California as well as those jurisdictions considering CCA.

TABLE 2-1. CCA PROGRAMS ACROSS THE STATE

	CCA/Entity	Status
PG&E Service Territory		
Marin Clean Energy	Marin and Napa Counties and cities within, cities in Solano and Contra Costa Counties	Launched 2010
Sonoma Clean Power	Sonoma and Mendocino Counties and cities within	Launched 2014
Peninsula Clean Energy	San Mateo County and cities within	Launched 2016
Silicon Valley Clean Energy	Santa Clara County and cities within (except San Jose)	Launched 2017
Pioneer Clean Energy	Placer County and cities within	Launched 2018
Central Coast Community Energy	Monterey, Santa Cruz, San Benito, and Santa Barbara Counties and cities within, cities of San Luis Obispo and Morro Bay	Launched 2018
East Bay Community Energy	Alameda County and cities within	Launched 2018
Valley Clean Energy	Yolo County, Cities of Davis and Woodland	Launched 2018
Redwood Coast Energy Authority	Humboldt County and cities within	Launched 2017
San Francisco Clean Energy	City/County of San Francisco (SF Public Utilities Commission)	Launched 2017
San Jose Clean Energy	City of San Jose	Launched 2018
King City Community Power	City of King City	Launched 2018
Butte Choice Energy Authority	Butte County, Chico, Oroville	2023 Launch
	Tuolumne County, Calaveras County, City of Stockton	Separate Feasibility Studies in Process
SCE Service Territory		
Clean Power Alliance	Los Angeles and Ventura Counties and cities within	Launched 2018
Lancaster Clean Energy	City of Lancaster, Member of California Choice Energy Authority (CCEA)	Launched 2015
Apple Valley Clean Energy	City of Apple Valley, Member of CCEA	Launched 2017
Pico Rivera Innovative Municipal Energy	City of Pico Rivera, Member of CCEA	Launched 2017
San Jacinto Power	City of San Jacinto, Member of CCEA	Launched 2018
Rancho Mirage Energy Authority	City of Rancho Mirage, Member of CCEA	Launched 2018

Desert Community Energy	Coachella Valley Association of Governments cities	Launched 2020
Western Community Energy	Western Riverside Council of Governments cities	Launched 2020
BProud	Baldwin Park (CCEA)	Launched 2020
Pomona Choice Energy	Pomona (CCEA)	Launched 2020
Orange County Power Authority	Cities of Irvine, Huntington Beach, Fullerton, Buena Vista	Launch in 2022
	, cities of Santa Barbara, Goleta, Carpinteria, Riverside County, Laguna Beach, Laguna Woods, Hanford	Feasibility Study Completed
	Cities of Long Beach,, Commerce, Mission Viejo, Stockton	Feasibility Studies in Process
SDG&E Service Territory		
Solana Energy Alliance	Solana Beach	Launched 2018
San Diego Community Power	San Diego, Encinitas, Chula Vista, La Mesa, Imperial Beach	Launch in 2021
Clean Energy Alliance	Carlsbad, Del Mar, Solana Beach	Launch in 2021
	County of San Diego	Feasibility and Business Plan completed
	Cities of Oceanside and Santee	Separate Feasibility studies completed

Additional potential CCA feasibility studies underway for Cities of Long Beach, Hermosa Beach, Commerce, El Monte, Rialto, Santa Paula, and Fresno.[5]

2.3 CCA AND CLIMATE ACTION PLANS

A number of the VSME Partner cities' CAP GHG reduction strategies and measures may be accomplished or supported through the implementation of a VSME Partner CCA.

A VSME Partner CCA can achieve the CAP measure of 90% renewable energy use by 2030 or better. In addition, a VSME Partner CCA can directly support CAP measures around clean energy implementation, in increasing solar photovoltaic installations on existing homes and the city facilities, and in increasing alternative powered water heaters in new residential construction. A VSME Partner CCA can provide both customer rate and direct incentives to encourage these actions.

[5] https://cleanpowerexchange.org/california-community-choice/

Examples of customer rate and direct incentives that support other GHG reduction strategies related to clean energy include:

- Supporting clean transportation strategies by providing a higher amount of GHG free energy for electric vehicles in both the private sector and in city operations.
- Encouraging more electric vehicle charging station installations and utilization.
- Incentivizing agricultural equipment conversions to clean and efficient electricity use.
- Prioritizing the purchase of local renewable generation such as waste-to-energy power production projects.

Most CCAs currently operating offer a rate discount compared with their incumbent IOU. Rate discounts range from 0.5% to 3% depending on a CCA's exit fee vintage, power supply product, and overhead costs. Very small CCAs have a more difficult time offering high discounts due to relatively high administration costs. For a CCA the size of a VSME Partner CCA, rate discounts around 1-2% are typical depending on exit fee vintage.

2.3.1 Time-of-Use (TOU) Rates

SDG&E has begun to move all customers to default Time-of-Use (TOU) rates, i.e., rates reflecting the actual temporal cost of procuring power supply by charging customers based on the hour of customer energy use. As SDG&E moves toward TOU rates for all accounts, information on SDG&E rate structures should be examined to help the CCAs operating in SDG&E service area to set rates while affording discounts to CCA customers. The rates used in this Study reflect SDG&E's forecasted average retail rate by customer class including the impacts of moving to TOU rate design. These TOU rates are expected to help incentivize the installation of solar plus battery systems by improving on-peak period economics for these resources.

2.3.2 CCA Regulations

The California Public Utilities Commission (CPUC) has jurisdiction over IOU rates. Additionally, the CPUC has jurisdiction over certain investor-owned and CCA operational processes such as the state-wide integrated resource planning (IRP) process, power system reliability, and renewable energy requirements. A VSME Partner CCA would be required to meet all CPUC requirements for Load Serving Entities (i.e., an entity that procures wholesale power and establishes retail rates on behalf of retail customers). Historically, the CPUC has changed regulations affecting the exit fee CCAs pay to the IOUs. This exit fee is known as the Power Charge Indifference Adjustment (PCIA). The PCIA is discussed in more detail later in this Study; however, recent changes in the PCIA resulted in a material one-time increase to the PCIA. This increase so far has been managed by operating CCAs as most have accumulated reserves from which to mitigate rate increases.

Similarly, recent legislative changes have impacted how CCAs operate including increasing the Direct Access cap (DA – supply of retail power to customers by third parties); integrated resource planning; and net energy metering. The result of these changes is that CCAs must meet planning requirements including the purchase of long-term renewable energy contracts to meet a share of renewable energy requirements (10 years or longer), energy storage investments, and resource adequacy (RA) requirements.

If the VSME Partners move forward with CCA implementation, they will need to participate in and keep track of a number of regulatory and legislative processes, including:

1. Resource Adequacy (RA, or grid reliability) The goal of current rulemaking is for RA resources to become widely available to market purchasers and to ensure grid reliability throughout the state. An RA proceeding for SCE and PG&E as central procurement entities is underway to set methodologies for RA obtained on behalf of other load serving entities, which would apply to SDG&E. Once a proposed decision or final decision is made, the methodology can be used to update CCA financial analyses.

2. As wildfire mitigation efforts increase costs to electric ratepayers through the distribution charge, it will become more nuanced for CCAs to explain rate discounts off the bundled rate even without changes in power supply costs because higher distribution rates (paid to IOUs) reduce the overall IOU rate discount amount offered by CCAs. CCAs have evolved from marketing a discount off the total electric bill to a discount off just the generation portion of the bill.

3. The CPUC may have future jurisdiction over CCAs for electric vehicle infrastructure requirements and the implementation of other Distributed Energy Resource projects.

Generally, there will likely continue to be legislation and regulatory changes increasing the amount of oversight the CPUC has over CCAs. CPUC oversight tends to lessen local control for a CCA. CCAs can help to mitigate these changes by being involved in the proceedings and legislative process through lobbyists and state-wide CCA organizations such as California Community Choice Association (CalCCA). Mitigation measures are further discussed in the Risks section of the Study. Overall, it is unlikely that future changes at the legislative level or at the CPUC would result in failure of CCAs.

2.4 STUDY METHODOLOGY

This Study evaluates the estimated costs and resulting rates of operating a CCA for the residents and businesses within the cities and compares these rates to an SDG&E rate forecast for the years 2023 through 2032. This pro forma financial analysis models the following cost components:

- Power Supply Costs:
  - Wholesale purchases
  - Renewable purchases
  - Procurement of resource adequacy (RA) and 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
  - SDG&E billing and regulatory charges
  - Financing costs
- Pass-Through Charges from SDG&E:
  - Transmission and distribution charges
  - Power Charge Indifference Adjustment (PCIA)

The information above is used to determine the projected retail rates for a VSME Partner CCA. The VSME Partner CCA rates are then compared to the SDG&E projected rates for the CCA service area. After these rate comparisons are made, economic development and GHG emission comparisons are made.

Operational and governance options are discussed, including a sensitivity analysis of the key variables contained in the Study.

3 Load Requirements

One indicator of the viability of a CCA for the unincorporated county is the number of customers that participate in the CCA as well as the quantity and timing of energy these customers consume. This section of the Study provides an overview of these projected values and the methodology used to estimate them.

3.1 HISTORICAL CONSUMPTION

SDG&E provided historical data on energy use (kWh) for each of the customers receiving power supply services from SDG&E (bundled customers) for 2017 and 2018 calendar years. Bundled customers currently purchase the electric power, transmission, and distribution from SDG&E. Direct Access (DA) customers buy only the transmission and distribution service from SDG&E and purchase power from an independent and competitive Electric Service Provider (ESP). 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.[6] Customers classified as taking service under DA arrangements are not included in this Study, as it is assumed that these customers would remain with their current Energy Service Provider (ESP).[7] Once operating, the CCA may decide to provide service options to DA customers with expired contracts, but this Study's approach offers the most conservative analysis of feasibility.

EES aggregated this data by rate class in each month for bundled (full service) customers. In total, bundled residents and businesses within the VSME Partner cities purchased 1,281 GWh of electricity in 2018 from SDG&E. These 2018 data were forecast assuming that load impacts of COVID-19 would not persist past 2022. On average, COVID-19 has resulted in increased residential usage and decreased industrial and commercial usage. However, by the time the CCA begins service, these impacts will likely be resolved.

Figures 3-1 and 3-2 summarize energy consumption and number of accounts for bundled customers projected over the study period. These projections are before any participation rates are applied. The load data was provided by SDG&E for each VSME City jurisdiction. The forecast assumes no significant annexations over the study period.

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

[7] 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.

FIGURE 3-1. FORECAST CCA SERVICE AREA LOAD

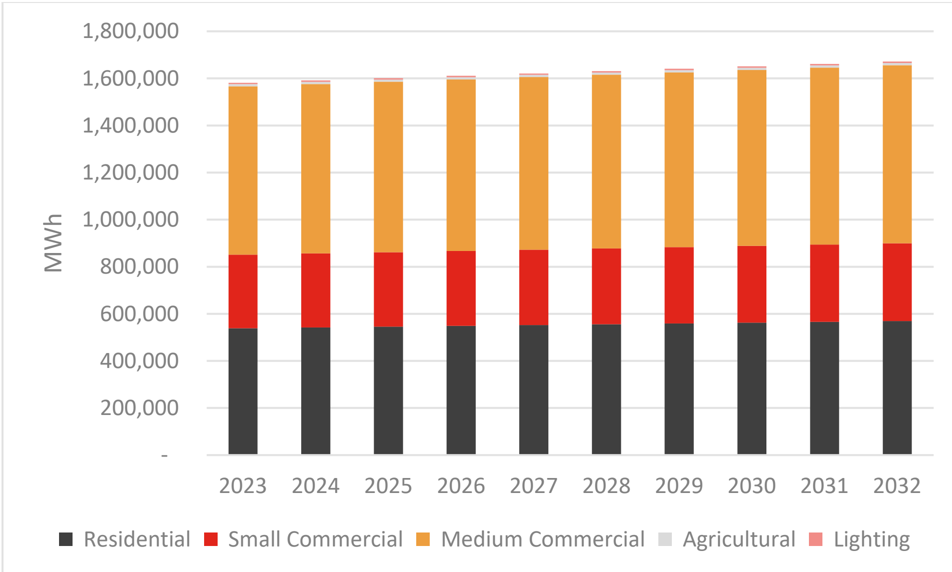
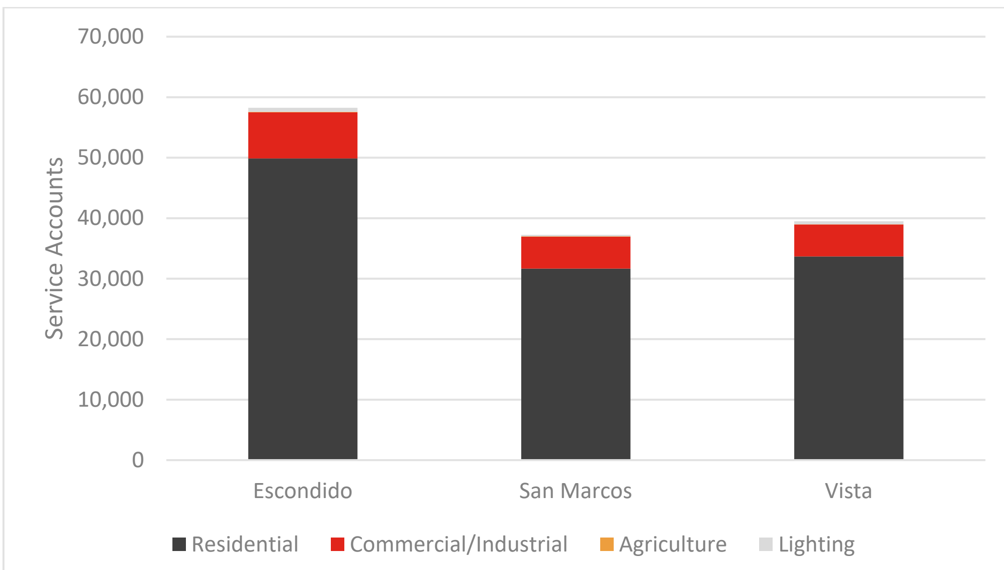
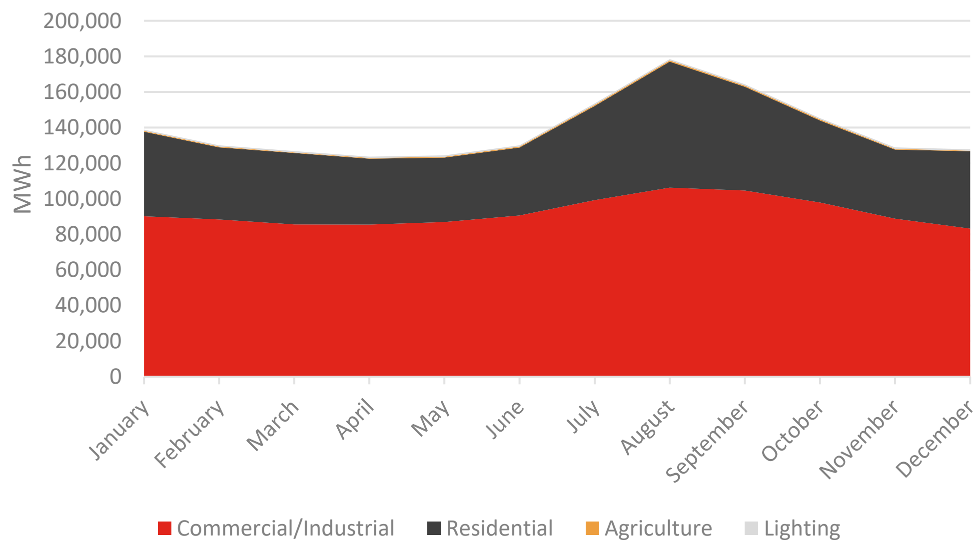


FIGURE 3-2. 2023 FORECAST SERVICE ACCOUNTS



Monthly load is shown in Figure 3-3. The timing of energy usage is important for estimating power supply costs to the CCA. Residential customers have the largest increase in summer load requirements due to space conditioning.

FIGURE 3-3. MONTHLY AGGREGATED LOAD



3.2 CCA PARTICIPATION RATES

Before customers are served by a CCA, they are required to be provided two notices with their monthly energy bills 60 and 30 days before the CCA's launch, and another two notices 30 and 60 days after the CCA launches. These notices provide information needed to understand the terms and conditions of service from the CCA and explain how customers can opt-out, if desired. Notices typically provide a rate comparison between the CCA and the incumbent IOU. All customers that do not follow the opt-out process specified in the customer notices prior to launch are automatically enrolled into the CCA.[8]

As such, a CCA would provide a minimum of four opt-out notices to customers to notify and educate them about the CCA's product offerings and their option to opt-out. Customers automatically enrolled would continue to have their electric meters read and billed for electric service by SDG&E. The CCA billing would also continue to be processed by SDG&E, showing separate charges for power supply procured by the CCA, all other charges related to the delivery of the electricity by SDG&E, and other utility charges that would continue to be assessed.

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

This Study anticipates an overall customer participation rate of 90% for the Commercial and Industrial accounts.[9] For residential accounts, it is assumed that approximately 95% of customers would remain with the VSME Partner CCA. For agricultural and lighting accounts, the participation rate is 95%. These participation assumptions are conservative based on participation rates in other CCAs; however, this Study's sensitivity analysis tested CCA feasibility under higher opt-out scenarios.

3.3 CONCEPTUAL CCA LAUNCH

In 2015 CPUC issued Resolution 4723, which requires that new CCAs file their Implementation Plan by January 1 of a year, resulting in an earliest possible launch date of January 1 of the subsequent year for the VSME Partner CCA. This twelve-month delay allows for the proper planning and procurement of the CCA's power supply requirements. Under this requirement, the earliest possible launch date for a VSME Partner CCA is early 2023. As requested by the Partners, this Study assumes that service would be offered to all customers by April 2023 as outlined in Table 3-1. An April launch is assumed to maximize net revenue in a CCA's first year of operation.

TABLE 3-1. CCA ANNUALIZED CUSTOMERS, LOADS, AND REVENUES

CCA Members	Assumed Start	Eligibility	Estimated Customer Accounts	Estimated Total Load (GWh)	Estimated Peak Demand (MW)	Estimated Operating Revenues
JPA: All Three Cities	April 2023	All Customers	128,153	1,581	464	$117.0
Escondido	April 2023	All Customers	55,358	666	205	$49.5
San Marco	April 2023	All Customers	35,447	431	122	$31.7
Vista	April 2023	All Customers	37,349	484	137	$35.8

3.4 FORECAST CONSUMPTION AND CUSTOMERS

The number of customers enrolled in the CCA and the retail energy they consume are assumed to increase at 0.62% per year. This forecast is selected as the midpoint based on the California Energy Commission's (CEC) mid-demand baseline forecasts for SDG&E service territory.[10] Peak demands are calculated using hourly consumption data provided by SDG&E. The forecast of load served by a CCA over the next five years is shown in Figure 3-4. The CCA forecast of GWh sales in Figure 3-4 reflects the single-phase roll-out and customer enrollment and participation schedule discussed previously. Annual wholesale energy requirements are also shown below in Table 3-2.

[9] Opt-out rates were increased to account for a 16% increase in the amount of non-residential load that is allowed to move to direct access schedules. California Senate Bill 237: September 20, 2018. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB237

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

FIGURE 3-4. PROJECTED LOAD BY SECTOR, 3-CITY JPA

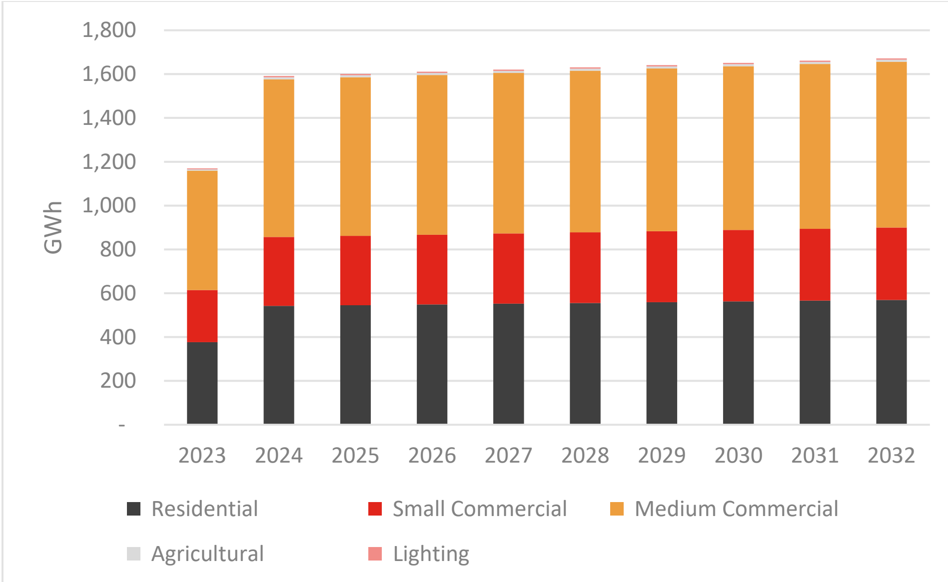


TABLE 3-2. 3 VSME CCA JPA PROJECTED ANNUAL ENERGY REQUIREMENTS, GWH

Year	Total Wholesale Load	Total Retail Sales	Losses
2023	1,159	1,108	51
2024	1,527	1,460	67
2025	1,536	1,469	68
2026	1,546	1,478	68
2027	1,556	1,487	68
2028	1,565	1,496	69
2029	1,575	1,506	69
2030	1,585	1,515	70
2031	1,594	1,524	70
2032	1,604	1,534	71

3.5 LOAD SUMMARY

The load in the three cities is significant and nearly the same size or larger than several existing CCAs including several JPAs. The VSME Partner CCA also has a large number of customers that can support the administrative costs for CCA operation. Economies of scale efficiencies for administration have been observed in the range of 75,000 to 100,000 accounts. The VSME Partner CCA service territory will have an estimated 128,153 accounts in 2023 and increase to an estimated 135,000 accounts by 2032.

4 Power Supply Strategy and Costs

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

Long-term resource planning involves load forecasting and supply planning on a 10- to 20-year time horizon. Prior to launch, the CCA planners would 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 non-renewable supply options. The CCA would 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 would ensure that local preferences regarding the future composition of supply and demand side resources are planned for, developed, and implemented.

4.1 RESOURCE STRATEGY

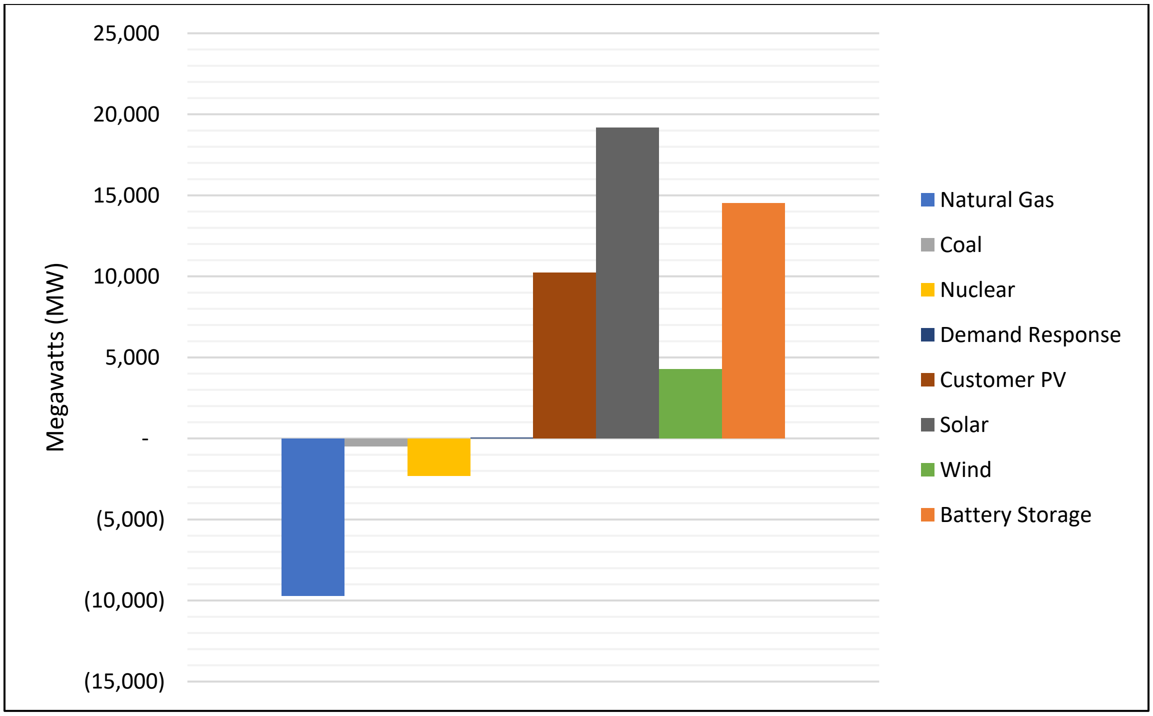
This Study assumes that the VSME Partner CCA would be interested in minimizing overall community energy bills, stimulating local economic development, achieving CAP targets to reduce GHG emissions, and meeting or exceeding the State's renewable energy requirements. A VSME Partner CCA can likely achieve the CAP renewable energy target in 2030 by taking advantage of relatively low wholesale market prices and abundant GHG-free energy. As discussed in greater detail below, the CCA's electric portfolio would be guided by the CCA's policymakers with input from its scheduling coordinator and other power supply experts. The scheduling coordinator would obtain enough resources each hour to serve all the CCA customer loads. The CCA policymakers would guide the power supply acquisition philosophy to achieve the CCA's policy objectives.

For the purposes of this study, it is assumed that the CCA would obtain power supply supporting the needs identified in the CPUC's state-wide IRP process. Those resources rely heavily on solar plus storage technologies. Background on the statewide IRP planning process is provided below.

4.1.1 Statewide IRP Results

All California Load Serving Entities (LSEs) submitted their 2020 Integrated Resource Plans (IRP) to the CA Public Utility Commission on September 1, 2020. These plans are mandated by the CPUC and reflect, at a high level, the anticipated growth of load and type of resources that will be utilized to meet it. The results of the statewide planning effort will likely not be available until early 2021; however, there is a significant amount of information already known about the resource plans filed by the LSEs. Specifically, the CPUC has established a state-wide reference system portfolio that meets the 38 million metric tons of Carbon Dioxide equivalent ($MMTCO_2e$) greenhouse gas (GHG) emissions benchmark by the year 2030. This portfolio shows reductions in conventional generation capacity and additions of renewable energy capacity. Figure 4-1 summarizes the changes in capacity for the statewide plan and is indicative of the expected statewide growth of renewables capacity by 2030.

FIGURE 4-1. 38 MMT REFERENCE SYSTEM PLAN CHANGE IN CAPACITY BY 2030[11]



According to the CPUC, a significant portion of new capacity additions will be solar and wind projects. The specific new solar projects evaluated in the statewide portfolio are located in the Greater Imperial area, Central Valley, Tehachapi, and in the southern California desert. The portfolio also accounts for imports from Arizona and New Mexico. The projected costs for these resources are used as a basis for the CCA power cost estimate.

4.1.2 CCA Power Portfolios

As noted early in this study, 3 power portfolios are analyzed for the VSME Partner CCA Option within the feasibility analysis:

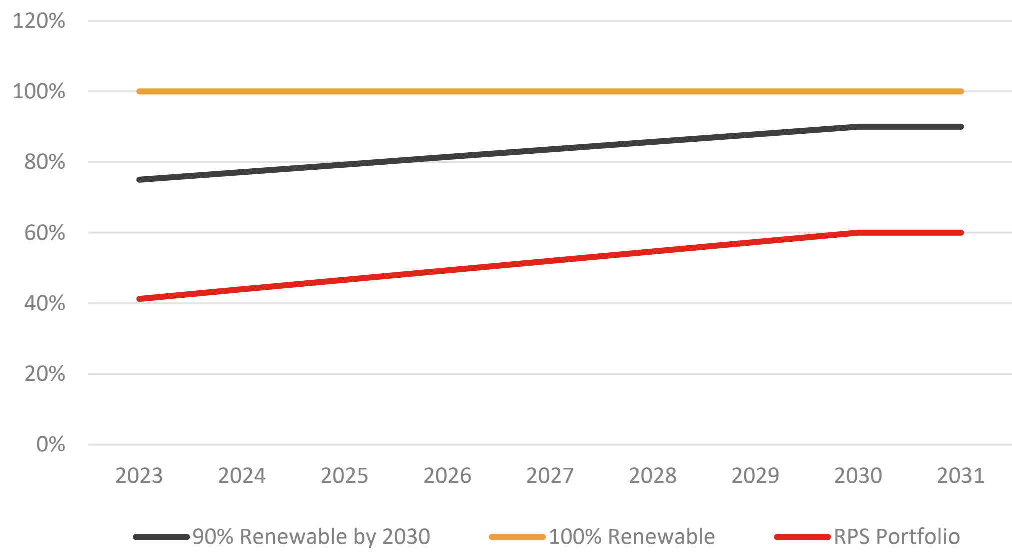
- **Scenario 1** *RPS Compliant Portfolio*: Achieve between 48% and 59% renewables in 2023 through 2029, and 60% renewables beginning in 2030.
- **Scenario 2** *90% Renewable by 2030 Portfolio (Base Case)*: 75% of retail loads are served with RPS-qualifying renewable resources beginning in 2023 increasing in share to 90% by 2030.
- **Scenario 3** *100% Renewables Portfolio*: 100% of retail loads are served with RPS-qualifying renewable resources in all years.

[11] California Public Utilities Commission. "2019-2020 IRP Events and Materials". Retrieved from <https://www.cpuc.ca.gov/General.aspx?id=6442459770>.

Additional portfolios are analyzed for VSME City-only options. Those portfolios meet the CAP goals for each respective VSME City.

It should be noted that while CCA policymakers may opt for other resource portfolios, those selected above should give the VSME Partners a sound basis for evaluating other resource portfolio options. The renewable energy targets of the three portfolios included in the power cost model are shown below in Figure 4-2. All power supply portfolios meet the RPS requirement (SB 100 and SB 350).

FIGURE 4-2. PORTFOLIO RENEWABLE ENERGY SHARE[12]



SDG&E's resource mix is compared with the portfolios analyzed to determine how competitive the CCA's resource offerings could be. SDG&E's current resource mix exceeds the current RPS requirements (43% renewable). In its 2020 IRP, SDG&E states that it plans to continue to exceed RPS requirements through 2030.[13] Figure 4-3 compares the 3 CCA portfolios to SDG&E's 2018 power content label.[14] SDG&E's renewable resources consist of a near 50/50 split between wind and solar.

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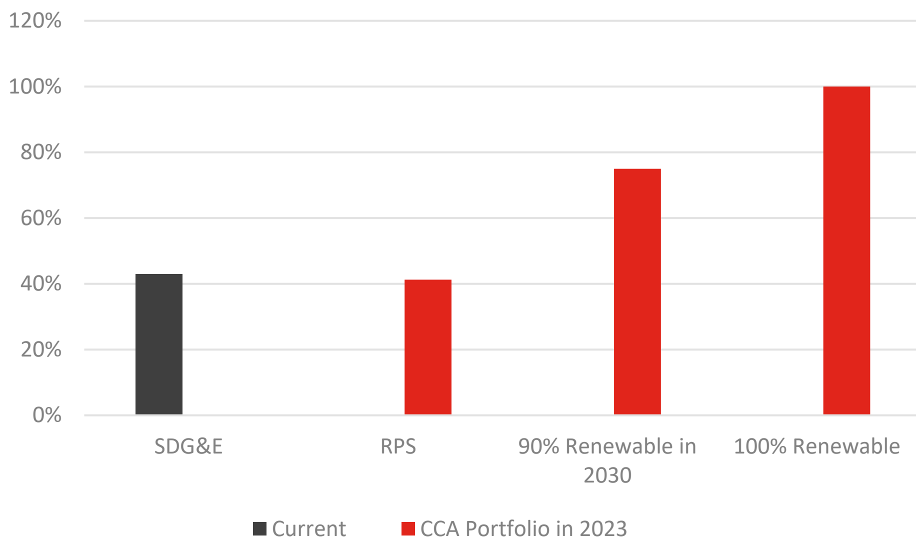
[12] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K845/158845742.PDF

[13] SDG&E 2020 Integrated Resource Plan. September 1, 2020. Available at: https://www.sdge.com/sites/default/files/regulatory/Appendix%202_SDGE%202020%20Individual%20Integrated%20Resource%20Plan_FINAL.pdf

[14] SDG&E 2018 Power Content Label July 2019. Available at: https://www.energy.ca.gov/sites/default/files/2020-01/2018_PCL_San_Diego_Gas_and_Electric.pdf

Note that SDG&E's 2020 power content label was not available at the time of this study.

FIGURE 4-3. RENEWABLE SHARE COMPARISON IN 2023



SDG&E has several contracts set to retire in the next 5 years including over 700 MW of natural gas and 300 MW of renewables (primarily wind). At the same time, the launch of SDCP and Clean Energy Alliance will reduce SDG&E's retail load by approximately 60% by the end of 2023. Based on these large upcoming load departures, it is expected that SDG&E will continue to offer a base power supply mix that exceeds the state RPS.

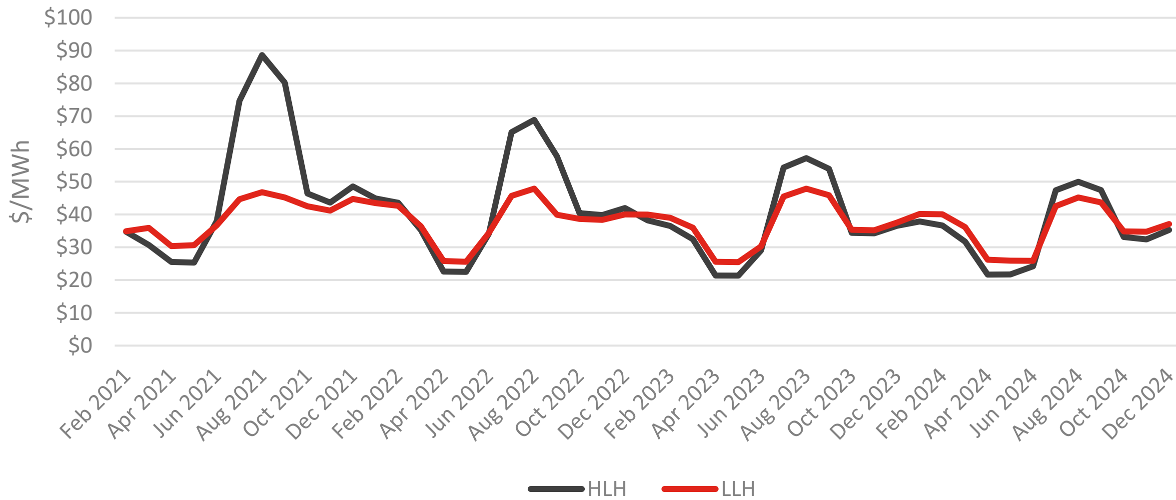
4.2 PROJECTED POWER SUPPLY COSTS

This Study presents the costs of renewable and non-renewable generating resources as well as power purchase agreements based on current and forecasted wholesale market conditions, recently transacted power supply contracts, and a review of the applicable regulatory requirements. In summary, a VSME Partner CCA would need to procure market purchases, renewable purchases, ancillary services, resource adequacy, and power management/schedule coordinator services. The Study determines the base case assumption for each of these cost categories and establishes a high and low range for each, to be used for the risk analysis later in the Study.

4.2.1 Market Purchases

Market prices for Southern California (referred to as SP15 prices) were provided by EES's subscription to a market price forecasting service, S&P Global. Figure 4-4 shows forecast monthly Southern California wholesale electric market prices. The levelized value of market purchase prices over the 10-year Study period is $0.042/kWh ($2021) assuming a 4% discount rate. Figure 4-4 shows the clear seasonal variability in prices each year, as well as the overall trend in prices.

FIGURE 4-4. FORECAST OF SOUTHERN CALIFORNIA WHOLESALE MARKET PRICES



Wholesale market 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 would schedule balancing purchases. When the CCA's loads are less than its resource capabilities, the CCA's scheduling coordinator would transact balancing sales and the CCA would receive market sales revenue. Balancing market purchases and sales can be transacted on a monthly, daily, and hourly basis, as needed.

4.2.2 Renewable Energy

4.2.2.1 Solar PV

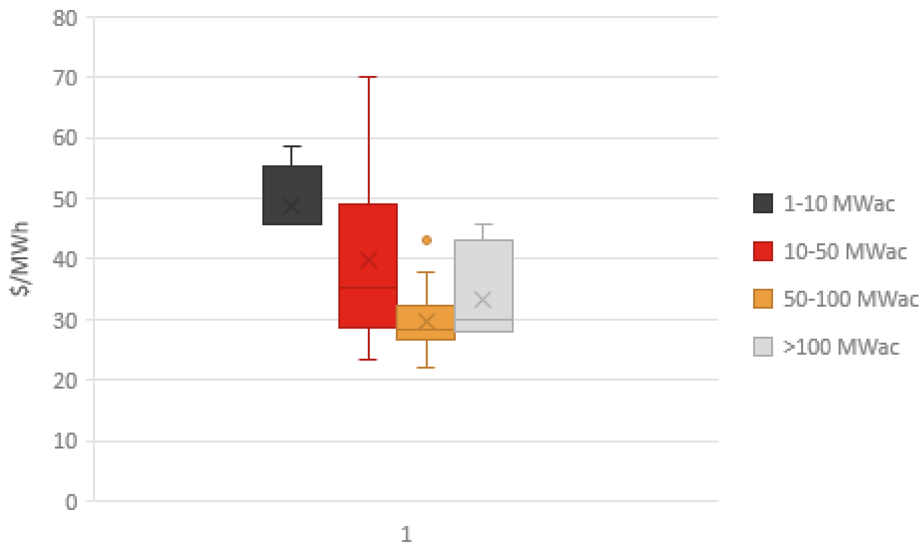
Utility-scale solar PV technology prices have fallen between 66% and 85% between 2010 and 2019.[15] Installation costs were approximately $4,700/kW in 2010 and are now about $1,000/kW. Capacity factors have also improved due to siting the resources in sunnier locations. California-specific solar PV capacity factors are around 24% compared to the global average of 18%. Arizona solar projects often have much lower prices and higher capacity factors.

Pricing estimates for solar power delivered to the San Diego region is summarized in Figure 4-5 by project capacity. As expected, solar project prices decrease as capacity increases. The chart shows that projects that are at least 10 MW in size could be cost competitive with solar prices from Arizona and New Mexico where contracts indicate pricing in the range of $20-$32/MWh. From a national perspective, Lazard indicates solar PV costs in the range of $31-$40/MWh.[16]

[15] https://www.irena.org/publications/2020/Jun/Renewable-Power-Costs-in-2019

[16] https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

FIGURE 4-5. SURVEY SOLAR PV PRICES IN CALIFORNIA, NEW RESOURCES



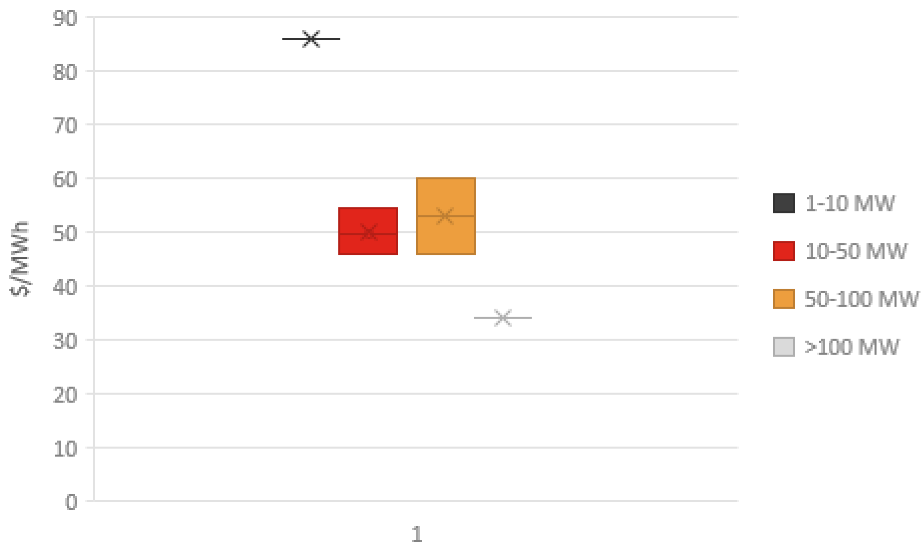
Many developers are including storage options to pair with solar PV. Battery storage costs an additional $4-$12/MWh. These costs are comparable to current resource adequacy prices for capacity.

4.2.2.2 Wind

Figure 4-6 shows the estimated pricing range for each wind project capacity category. Small projects are not price competitive; however, larger utility scale projects are in the $30/MWh range. 2020 cost data from Lazard shows that wind costs are in the range of $23-$46/MWh in the U.S.[17] These prices include high capacity factor wind in places like Wyoming. Capacity factors for local wind projects in California are typically much lower resulting in higher energy costs.

[17] https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/

FIGURE 4-6. SURVEY WIND PRICES IN CALIFORNIA, NEW RESOURCES



4.2.2.3 Battery Storage

The CPUC and CAISO have both emphasized the importance of battery storage technologies in resource planning. The capacity values for wind and solar are small compared with baseload resources. As the penetration of these variable resources increases, battery storage is expected to offset some of the open capacity requirements. Short-term lithium-ion batteries are a widely available technology that is expected to grow at an exponential pace in California in the next 2 years. These storage resources are typically short-term resources providing 4-6 hours of energy daily. High on-peak pricing during evening hours create significant incentive for these short-term, lower cost resources. As mentioned above, short-term battery storage can add a 4-$12/MWh to solar or wind project costs. These resources provide very little energy (negative net energy), but they are needed to meet resource adequacy requirements under high renewable scenarios. Other storage options may become available to the CCA including pumped storage and long-term storage technologies.

4.2.3 Renewable Energy Credits (RECs)

In addition to direct purchases of renewable power, renewable energy credits (RECs) are an alternative for meeting RPS requirements. However, RECs are highly restricted and not always the best alternative. California load serving entities (LSE)[18] must purchase bundled energy and/or RECs that meet certain eligibility requirements across three Portfolio Content Categories (PCC). Each of the categories represents a different type of renewable product that can be used to meet up to a specific percentage of the total procurement obligation during a compliance period. The permitted percentage shares of each category

[18] Load serving entities include entities that serve retail load, including IOUs, CCAs, and public utilities including municipal utilities.

type changes over time. The three PCCs, and the type of energy included in each, are be summarized as follows:

- **PCC1**: Bundled renewable resources and RECs – either from resources located in California or out-of-state renewable resources that can meet strict scheduling requirements ensuring real-time delivery into California.
- **PCC2**: Renewable resources that cannot be delivered into California on a real-time basis without some substitution from non-renewable resources[19]. This process of substitution is referred to as "firming and shaping" the energy. The firmed and shaped energy is delivered and then bundled with RECs.
- **PCC3**: Unbundled RECs, which are sold separately from the electric energy.[20]

Under current guidelines, the quantity of RECs that can be procured through PCC2 and PCC3 is limited and decreases over time. SBX1 2 (April 2011) established a 33% RPS requirement for 2020 with certain procurement targets prior to 2020. SB 350 (October 2015) increased the RPS requirement to 50% by 2030. Finally, SB 100 increased RPS to 60% by 2030. The share of renewable power that can be sourced from PCC2 or PCC3 energy after 2020 is expected to be the same as the 2020 required share of total RPS procurement.[21] All power supply portfolios are modeled to meet the relevant state mandates. All load serving entities face the same mandates and resource choices.

4.2.4 Ancillary Service Costs

The CCA would need to pay the California Independent System Operator (CAISO) for transmission congestion and ancillary services associated with its power supply purchases. 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 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 need to be purchased from the CAISO based on the CCA's total load

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[19] 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.

[20] 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.

[21] 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. 75% of the RPS procurement must be Bucket 1 resources and less than 10% of the RPS procurement can come from Bucket 3 resources.

requirement. Based on a survey of transmission congestion and ancillary service costs currently paid by CAISO participants, the VSME Partner CCA Base Case ancillary service costs are estimated to be approximately $4/MWh, escalating by 3% annually through 2032.

4.2.5 Resource Adequacy

All LSEs that are participants in the CAISO balancing area, including CCAs, are under the jurisdiction of the CPUC for the purpose of obtaining adequate Resource Adequacy (RA). RA refers to the ability of a resource to meet capacity obligations under various criteria. Three types of RA are defined and regulated by the CPUC:

- *System capacity* is capacity from a resource qualified for use in meeting system peak demand and planning reserve margin requirements.
- *Local capacity* is from a resource that is located within a Local Capacity Area and can contribute to the capacity requirement for that area.
- *Flexible capacity* is from a resource that is operationally able to respond to dispatch instructions to manage variations in load and variable energy resource output.

The CCA would need to demonstrate it has sufficient physical power supply capacity to meet its projected peak demand plus a 15% planning reserve margin as determined by the CPUC in consultation with CEC load forecasts system capacity). Year-ahead filings must show that the LSE has contracted for 90% of the projected System RA requirement in summer months (May-September). The forecasts must be updated on a month-ahead basis and show that 100% of the requirement has been contracted.

In addition, the CCA must meet the local and flexible resource adequacy requirements set by the CPUC, CAISO, and CEC every year. Local RA requirement must be met by LSEs serving 10 local reliability areas identified by the CAISO. The Local RA requirement is based on the CAISO's assessment of the generation needed in the local area. Beginning with the 2020 compliance year, the Local RA requirements are set three years ahead and updated each year. However, on June 11, 2020, the CPUC adopted a framework (D. 20-06-002) that designated a central buyer for the procurement of multi-year Local RA in the SCE and PG&E distribution areas, beginning in 2021. The CPUC did not establish a central procurement entity in the SDG&E area; however, SDG&E may become the default central procurement agency in the future as a result of CCA implementation. This feasibility analysis assumes pricing and procurement structure based on historic and forecast values.

The CAISO also determines the required Flexible RA needs operating criteria. Currently there are three flexible capacity categories with varying must-offer obligations, energy limits and number of starts, with associated requirements for how much of each category may be used to meet the LSE's obligation. LSEs must demonstrate the purchase of 90% of their flexible RA requirement in their annual RA filing, and 100% of the requirement in their monthly RA filings.

Depending on generation profiles and ramping characteristics, resources have different capacity values for RA compliance purposes, and those values can change by month. Due to their generation profiles, recent rule changes have reduced the RA values for wind and solar resources. These structural changes highlight the need for the CCA to obtain capacity resources such as storage. There is a bilateral market for RA capacity, with standardized products for each type of RA capacity.

The CPUC's published market price benchmarks are used to forecast RA costs for each type of RA above.[22] These annualized benchmarks are shaped to reflect higher prices in the summer, which are often 2 or 3 times greater than winter RA prices. The CPUC undertakes annual policy changes to the RA program, so these requirements may change by the time program launch occurs.

4.2.6 Power Management/Schedule Coordinator

Given the likely complexity of a CCA's resource portfolio, the CCA would want to engage an experienced scheduling coordinator to efficiently manage the CCA's power purchases and wholesale market transactions. The CCA's resource portfolio would 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 and complex functions of the CCA.

The CCA should initially contract with a third party possessing the necessary experience (proven track record, longevity, and financial capacity) to perform most of the CCA's portfolio operation requirements. This would 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 CCA customers.
- *Risk Management* – standard industry risk management techniques would 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 SDG&E billing to customers.

A CCA should approve and adopt a set of protocols that would serve as the risk management tools for the CCA and any third-party involved in the CCA portfolio operations. Protocols would 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 would bear most of the risk and be responsible for managing those risks. The protocols that cover electricity procurement activities should be developed before operations begin.

Based on conversations with scheduling coordinators currently working within the CAISO footprint, the estimated cost of scheduling services is $10,000 to $15,000 per month. For this study, schedule

[22] California Public Utility Commission. Calculation of the Market Price Benchmarks for the Power Charge Indifference Adjustment Forecast and True-Up. November 2, 2020.

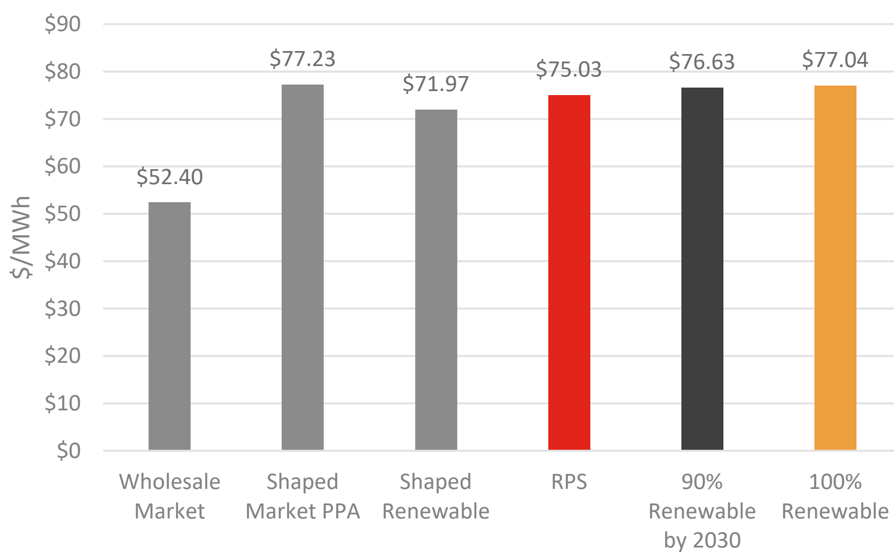
coordinator service costs are assumed at $10,000 plus another $16,000 per month for power procurement and risk management services.

4.3 RESOURCE PORTFOLIOS

Projected power supply costs were developed for three representative resource portfolios. For each of the resource portfolios, a combination of resources has been assumed to meet the renewable energy and GHG-free targets, resource adequacy targets, and ancillary and balancing requirements. The mixes of resources included in each portfolio are for analytical purposes only. The CCA should be flexible in its approach for obtaining the renewable and non-renewable resources necessary to meet these requirements.

Figure 4-7 shows the levelized resource costs used in this Study. It compares the costs of wholesale market power prices, a Power Purchase Agreement (PPA) tied to the wholesale market power prices, blended and shaped renewables, and the three portfolios evaluated in the Study.

FIGURE 4-7. BASE CASE LEVELIZED RESOURCE COSTS ($2021/MWH)



The levelized resource costs shown above include ancillary services, RA and necessary carbon free purchases for RPS PCC2 compliance. Scheduling services and other costs are not included. These costs would not change significantly due to different portfolio choice (90%, 95% or 100% renewable).

4.3.1 Renewable PPA Pricing

4.3.1.1 Short-Term Renewable Energy Contract Price

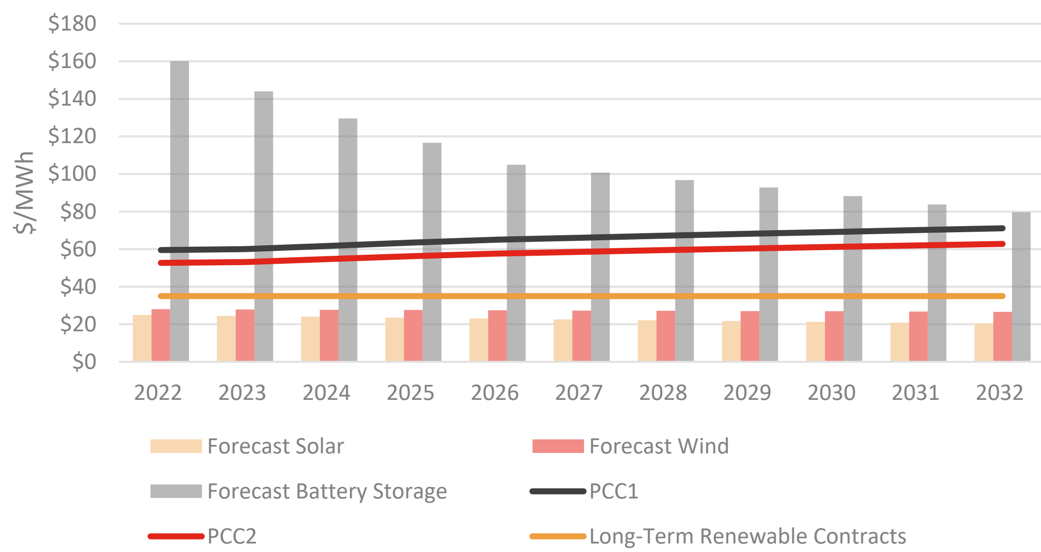
Short-term contracts have a term of fewer than 10 years. Short-term contract prices include two components: a price for energy that is based on forward wholesale market prices and a price for Renewable Energy Credits (RECs). To minimize power costs, it is assumed that the maximum amount of PCC2 RECs are purchased to meet unbundled REC allowances. This means that 75% of unbundled RECs are PCC1 and the remaining 25% are PCC2 RECs. PCC2 RECs are not considered carbon free by the CPUC, therefore, an equal quantity of GHG free power is purchased to equate PCC2 RECs to the same GHG content as PCC1 RECs.

4.3.1.2 Long-Term Renewable Energy Contract Price

The Study's base case includes a long-term renewable PPA fixed contract price of $35/MWh (all years). The $35/MWh assumption is conservative as other CCAs are currently signing PPAs for the output of solar projects with flat contract prices in the range of $20-$32/MWh for solar and wind, respectively. This higher price allows for both smaller-scale local projects to be added to the CCA resource mix and for solar plus battery resources. Typical solar plus battery storage resources have been offered at $25-$45/MWh.

The power supply costs are based on 65% of the RPS requirement purchased via the lower-cost long-term contracts beginning in 2023 to meet SB 350 requirements, as shown in Figure 4-8. The share of long-term contracts increases from 65% to 75% by 2030 to take advantage of lower cost renewables.

FIGURE 4-8. FORECAST POWER COSTS VS. FORECAST DEVELOPMENT COSTS



The above forecasts for specific resources are based on the Energy Information Administration (EIA) and Lazard sources for historic costs. Lazard shows a 5% decrease in unsubsidized wind costs from 2015-2020 and an 11% decrease in solar costs over the same period.[23] The EIA reports storage technologies have decreased in cost by 70% from 2015-2018.[24] Given these trends, the renewable prices used in the study are conservatively high.

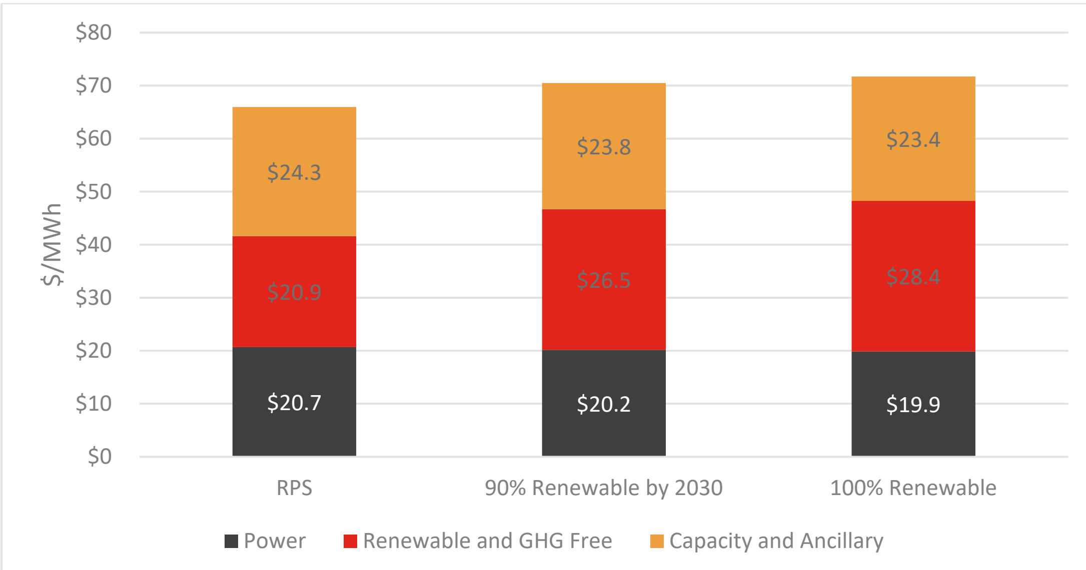
[23] https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/

[2424] https://www.eia.gov/todayinenergy/detail.php?id=45596

4.4 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. Figure 4-9 shows a breakdown of power, renewable, and ancillary service costs components associated with each portfolio.

FIGURE 4-9. LEVELIZED BASE CASE PORTFOLIO COSTS ($/MWH)



As shown above, power costs under the three portfolios considered are similar except for the renewable component in each portfolio. There is a low level of power cost variance between these portfolios because the majority of power is supplied by market PPAs and renewable energy purchases, which are very close in cost. The difference is driven by the amount of renewable energy relative to the entire portfolio.

4.5 RESOURCE STRATEGY

A third-party vendor may manage a CCA's electric portfolio, at least during the initial implementation period. Through a power services agreement, a CCA 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. The contracted power services manager would assist the CCA in meeting resource portfolio requirements such as the requirements for long-term renewable energy contracts and energy storage requirements. The costs for these resources are factored into the feasibility analysis.

After operations have begun, a CCA could decide to sign long-term PPAs, which could minimize the CCA's exposure to market prices and provide the CCA with the ability to increase the renewable percentage over time. Additionally, it is recommended that the CCA engage with a portfolio manager or schedule coordinator, who has expertise in risk management and would work with the CCA to design a comprehensive risk management strategy for long-term operations. A portfolio manager or schedule coordinator would 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.

Once operational, the CCA will be subject to energy storage targets under AB 2514, the California Energy Storage Bill. AB 2514 was signed into law in September 2010 and established energy storage targets for IOUs, CCAs, and other LSEs in September 2013. The applicable CPUC decision established an energy storage procurement target for CCAs and other LSEs equal to 1% of their forecasted 2020 peak load. The decision requires that contracts be in place by 2020 and projects be installed by 2024. This requirement means that a VSME Partner CCA would need to issue an RFP for storage projects in its initial power supply procurement process.

5 Cost of Service

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

5.1 COST OF SERVICE FOR CCA OPERATIONS

The first category of the pro forma analysis is the cost of service for a VSME Partner CCA. To estimate the overall costs associated with CCA operations, administration costs are estimated and added to the power supply cost estimates. Once the costs of CCA operations have been determined, the total costs can be compared to SDG&E's projected rates.

5.2 NON-POWER SUPPLY COSTS

While power supply costs would make up the vast majority of costs associated with operating the VSME Partner CCA (power supply costs are roughly 90-95% total operating expenses), there are additional cost components that must be considered in the pro forma financial analysis. These additional non-power supply costs are summarized in Table 5-1 and then described below.

TABLE 5-1. ANNUAL NON-POWER SUPPLY COSTS

	One-Time Costs	2022	2023	2024
CAISO Deposit	$500,000			
SDG&E Security Deposit	$147,000			
CPUC Bond	$100,000			
Customer Notification	$300,000			
Billing & Data Management		$0	$1,177,000	$1,608,000
Power Management and Scheduling		$0	$225,000	$306,000
SDG&E Metering & Billing Fees		$0	$323,000	$441,000
General Legal, Regulatory, Power Contracts		$78,000	$316,000	$479,000
Marketing		$88,000	$153,000	$78,000
Technical Consulting Services		$113,000	$230,000	$260,000
Memberships		$0	$57,000	$78,000
Staffing		$0	$696,000	$1,097,000
General & Administrative Expenses		$0	$101,000	$103,000
Debt Service		$0	$2,299,000	$3,080,000
Total One-Time Costs	**$1,047,000**			
Total Operating & Administration Costs		**$279,000**	**$5,577,000**	**$7,530,000**

Pre-launch costs in 2022 can be variable depending on how quickly the CCA wants to begin outreach. The estimate in Table 5-1 is considered the minimum and is budgeted based on the $600,000 in start-up funds provided by member cities.

5.2.1 Estimated Staffing Costs

Staffing is a key component of operating a CCA. The VSME Partner CCA would have discretion to distribute operational and administrative tasks between internal staff and external consultants in any combination. For this Study, a limited staffing scenario is modeled. This minimum staff scenario relies on a few dedicated full-time staff members and the use of technical consultants for support. If the CCA finds that there are cost savings for increasing the number of organization staff, feasibility of this scenario would improve.

Based on the minimal staffing plan, the VSME Partner CCA would initially rely on staff from member cities and hire a CEO in 2023. Once the CCA launches, it is anticipated that staffing would increase to approximately 4 employees within the first year of operation. It should be noted that if the one or more of the Partners choose to join another CCA, there would likely be some economies of scale savings for overhead such as staffing.

5.2.2 General and Administrative Costs and Membership

Overhead needed to support the organization includes computers and other equipment, office furnishings, office space, utilities, and miscellaneous expenses. These expenses are estimated at $101,000/ year and escalated at 2%. A nominal fee is included for memberships. Many CCA's find the CalCCA membership valuable and become members after launch.

5.2.3 Outside Consultant Costs

Consultant costs would include outside assistance for legal and regulatory work, power supply management, 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 and service, as well as payment processing, accounts receivable, and verification services. The cost of data management is charged on a per customer basis and has been estimated based on existing contracts for similarly sized CCAs. For this Study, the cost for data management is estimated at $1.00 per account per month.

In addition, estimated funding for other consulting support (such as human resources, legal, customer service, etc.) is provided. These costs have been estimated based on the experience of start-up consulting costs at other CCAs. The estimate for each of the services is based on costs experienced by other CCAs. Consultant costs are increased by inflation every year.

5.2.4 SDG&E Fees

SDG&E would provide billing and metering services to the VSME Partner CCA based on Schedule CCA: Transportation of Electric Power to CCA Customers. The estimated costs payable to SDG&E for services related to the VSME Partner CCA start-up include costs associated with initiating service with SDG&E, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees.

5.2.5 Uncollectible Costs

As part of its operating costs, the CCA must account for customers that do not pay their electric bill. While SDG&E would attempt to collect outstanding funds, approximately 0.2% of revenues are estimated as uncollectible.[25] This cost is removed from the revenue projection in the proforma. It should be noted that uncollectible revenues will increase during economic downturns. The assumption in this study reflects long-term averages.

5.3 FINANCIAL RESERVES

The CCA is assumed to receive capital financing during its start-up through full operation. After a successful launch, a CCA should build up a reserve fund that is available to address contingencies, cost uncertainties, rate stabilization, or other risk factors faced by the CCA. This Study assumes that a CCA would begin building its reserve immediately upon launch. After five full operating years, it is estimated that the CCA will have accumulated enough reserves to cover four months of expenses. This level of reserves represents the industry standard for electric utilities and would provide financial stability to assist the CCA in obtaining favorable interest rates if additional financing is needed. After that point, revenues that exceed costs could be used to fund a reserve to mitigate rate changes, procure new local renewable resources, and pursue economic development projects and/or lower rates. Table 5-2 provides an estimate of the revenues available for local programs, rate stabilization, or additional rate discounts in excess of 2%. These financial reserves may be utilized for cash flow and to stabilize rates in response to market conditions or exit fee changes.

TABLE 5-2. RESERVES AND NEW PROGRAM ACCOUNT BALANCES, MILLIONS

	Reserve Fund Balance*	Operating Reserve Target (4 months O&M)	New Programs or Rate Reduction
2023	$0.6	$0.1	$0.0
2024	$25.8	$25.8	$9.4
2025	$33.4	$33.4	$8.5
2026	$33.8	$33.8	$17.3
2027	$34.3	$34.3	$17.6
2028	$34.8	$34.8	$19.1
2029	$34.0	$34.0	$25.2
2030	$34.7	$34.7	$24.7
2031	$35.4	$35.4	$25.6
2032	$36.0	$36.0	$26.9
** Includes cash from financing*			

[25] Based on SDG&E 2019 GRC uncollectible revenue as percent of total revenue.

5.4 FINANCING COSTS

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

5.4.1 Cash Flow Analysis and Working Capital

This cash flow analysis estimates the level of working capital that would be required until full operation of the CCA is achieved. For the purposes of this Study, it is assumed that the CCA pre-operations begin in January 2022. 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 CCA customers.

The cash flow analysis also provides estimates for revenues generated from CCA operations. In determining the level of revenues, the cash flow analysis assumes that all customers are enrolled at the same time. 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 payment terms, along with the timing of customer payments and power supply bill payments.

The cash flow analysis assumes that customers will make payments within 60 days of the service month, and that the CCA would make payments to power suppliers within 30 days of the service month. It is assumed that payments for all non-power supply expenses would need to be paid in the month they occur. Customer payments typically begin to come in soon after the bill is issued, and most are received before the due date; however, some customer payments are received well after the due date. The 30-day net lag in payment is therefore a conservative assumption for cash flow purposes.

For purposes of determining working capital requirements related to power purchases, the CCA would 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 would be obligated to meet working capital requirements related to program management, the SDG&E program reserve of $147,000.[26] While the CCA may be able to utilize a line of credit, for this Study it is assumed that the working capital requirement is included in the financing associated with start-up funding. The Study finds that the CCA will need as much as $13 million in working capital and start-up funds. The CCA will also likely need an additional $5-10 million for power supply contract collateral.

For comparison, Marin Clean Energy (MCE) started with $3.3 million in pre-launch funding[27] and is now operating with $21.7 million in working capital.[28] Similarly, Sonoma Clean Power (SCP) acquired $6.2

[26] CPUC Decision 18-05-022

[27]https://www.mcecleanenergy.org/wp-content/uploads/2016/01/MCE-Start-Up-Timeline-and-Initial-Funding-Sources-10-6-14-1.pdf

[28]https://www.mcecleanenergy.org/wp-content/uploads/2016/09/MCE-Audited-Financial-Statements-2015-2016.pdf

million in pre-launch capital,[29] and now maintains working capital reserves of $25 million[30] while serving 25% more than the VSME Partner CCA's estimated load.[31] The working capital needs after launch assumed in this Study are reflective of the experience of successfully operating CCAs on a $/GWh basis.

5.4.2 Total Financing Requirements

The start-up of a VSME Partner CCA would require an amount of start-up capital for three major functions: (1) staffing and consultant costs; (2) overhead costs (office space, computers, etc.); and (3) CPUC Bond and SDG&E security deposits. The study assumes that a $500,000 CAISO fee is financed and repaid within 12 months of funding the cash for working capital loan.

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 re-entry fees imposed on customers that are involuntarily returned to SDG&E service under certain circumstances. SDG&E also requires a bond equivalent to the re-entry fee for voluntary returns to the IOU. This corresponds to the fees outlined in the CCA rate schedule from SDG&E. In addition, the bond must cover incremental procurement costs. Incremental procurement costs are power supply costs incurred by the IOU when a customer provides notice and returns to IOU bundled service. These incremental procurement costs are minimal as SDG&E has a surplus of power supply resources.

For a VSME Partner CCA, the total financing requirement, including working capital, collateral requirements, and start-up costs is $18 million.

5.4.3 Current CCA Funding Landscape

The CCA market is rapidly expanding with increasingly proven success. To date, existing CCAs have demonstrated the ability to generate positive operating results. The early sources that funded CCA start-up capital costs were community banks located in the CCA service territory, but now a mix of regional and large national banks have shown increased levels of interest evidenced by additional banks submitting proposals to CCAs in need of financing. As such, a VSME Partner CCA would likely 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 demonstrated an increased level of comfort in providing credit support to CCAs. Most programs that have launched to date, along with 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 Table 5-3. During the COVID-19 pandemic, SDCP relied on loan securitization from a local philanthropist. This arrangement is the only one of its kind to date and should not be considered a new normal.

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[29] https://sonomacleanpower.org/wp-content/uploads/2015/01/2014-SCPA-Audited-Financials.pdf
[30] https://sonomacleanpower.org/wp-content/uploads/2015/01/2016-05-SCP-Compiled-Financial-Statements.pdf
[31] https://sonomacleanpower.org/wp-content/uploads/2015/01/2015-SCP-Implementation-Plan.pdf

TABLE 5-3. CCA FINANCIAL MECHANISMS

CCA Name	Date	Pre-Launch Funding Requirement[1]	Funding Sources
Marin Clean Energy	2010	$2- $5 million	Start-up loan from the County of Marin, individual investors, and local community bank loan.
Sonoma Clean Power	2014	$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	2016	~$5 million	Appropriations from the Hetch Hetchy reserve (SFPUC).
Lancaster Choice Energy	2015	~$2 million	Loan from the City of Lancaster General Fund.
Peninsula Clean Energy	2016	$10 - $12 million	PCE obtained a $12 million loan with Barclays and almost $9 million with the County of San Mateo for start-up costs and collateral.
Silicon Valley Clean Energy	2017	$2.7 million	Loans from County of Santa Clara and City members, $21 million Line of Credit with $2 million guarantee, otherwise no collateral.
Clean Power Alliance	2018	$41 million	$10 million loan from Los Angeles County and $31 million Line of Credit from River City Bank.
Solana Energy Alliance	2018	N/A	Vendor Funding
East Bay Clean Energy	2018	$50 million	Revolving Line of Credit from Barclays.
Western Community Energy	2019	$13 Million	Revolving Line of Credit from Barclays
San Diego Community Power	2020	$40 million	Philanthropist loan securitization $5 million, River City Bank Loan $5 million pre-launch loan plus $35 million line of credit

[1] Source: Respective entity websites and publicly available information. These funds are representative of CCA funding at different times of start-up.

A review of the current state of options for obtaining funds for these initial phases is detailed below:

<u>Direct Loan from the Member Cities</u> – The VSME Partners could loan funds from their General Funds for all or a portion of the pre-launch through launch needs. Start-up funding provided by the Partners would be secured by the CCA's revenues once launched. The VSME Partners would likely assess a risk-appropriate rate for such a loan. This rate is estimated to be 4.0% to 6.0% per annum.

<u>Collateral Arrangement from the Cities</u> – As an alternative to a direct loan from the VSME Partners, the VSME Partners could establish an escrow account to backstop a lender's exposure to the CCA. The Cities 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. The VSME Cities' obligations would be secured by CCA revenues collected once the CCA is launched.

<u>Loan from a Financial Institution without Support</u> – Silicon Valley Clean Energy Authority (SVCEA) was able to use this option to fund ongoing working capital. After member agencies funded a total of $2.7 million in start-up funds, SVCEA obtained a $20 million line of credit without collateral. This is the most common financing option used by emerging CCAs. This arrangement typically requires a "lockbox" approach with a power provider. A lockbox arrangement requires the CCA to post revenues into a "lockbox" which power

suppliers can access in order to get paid first before the CCA. This arrangement reduces the required reserves and collateral required of a CCA.

Vendor Funding – The CCA could negotiate with its power suppliers or other vendors to eliminate or reduce the need for supplemental start-up and operating capital. However, the vendor funding approach can be less transparent as the vendor controls expenses and activities, and the associated cost may outweigh the benefit of eliminating or reducing the need for bank financing.

Revenue Bond Financing – This financing option becomes feasible only after the CCA is fully operational and has an established credit rating.

5.4.4 CCA Financing Plan

While there are many options available to the CCA for financing, it is expected that initial start-up funding will be provided via short-term financing with a loan from a financial institution. The CCA would recover the principal and interest costs associated with the start-up funding via subsequent retail rate collections. This Study demonstrates that the CCA start-up costs would be fully recovered within the first five years of CCA operations.

The anticipated start-up and working capital requirements for a VSME Partner CCA through launch are approximately $600,000 for pre-startup costs, $13 million for working capital, and $5 million for power supply collateral. Once the CCA program is operational, these costs would be recovered through retail rate collections. Actual recovery of these costs would be dependent on third-party electricity purchase prices and the rates set by the CCA for customers.

Based on several recent examples of CCAs obtaining financing for start-up and operating costs, this financial analysis assumes that the CCA would be able to obtain a loan for all $18 million with a term of 5 years at a rate of 5.0%. This is very conservative, as most CCAs will operate on a line of credit for the majority of working capital needs. The detail of the cash flow analysis is provided in the Appendix.

6 Rate Comparison

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

6.1 RATES PAID BY SDG&E BUNDLED CUSTOMERS

Customers served by SDG&E will pay a bundled rate that includes SDG&E's generation and delivery charges. SDG&E's current rates and surcharges have been applied to customer load data aggregated by major rate schedules to form the basis for the SDG&E rate forecast.

The average SDG&E delivery rate, which is paid by both SDG&E bundled customers and CCA customers, has been calculated based on the forecasted customer mix for a VSME Partner CCA. The SDG&E rate forecast assumes that delivery costs will be based on SDG&E's recent General Rate Case (GRC) filing for 2019 to 2021. Thereafter, it is assumed that the delivery costs will increase by 2% per year based on inflation expectations. Similarly, the average power supply rate component for SDG&E bundled customers has been calculated based on the projected CCA customer mix.

Finally, the SDG&E generation rates have been projected to increase 1-2% per year. These cost projections are consistent with a power market that has experienced decreasing energy costs but increasing capacity costs. It's expected that the primary driver for SDG&E generation rate forecasts will be for capacity resources and the sale of excess contracts where the cost to SDG&E of those contracts exceeds the market value. These above market costs will be shared among both bundled and unbundled customers through the PCIA.

6.2 RATES PAID BY CCA CUSTOMERS

The Study assumes that VSME Partner CCA rate designs would initially mirror the structure of SDG&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. SDG&E is moving towards Time-of-Use (TOU) rates for all customers and it is assumed that the CCA would follow this transition initially. In determining the level of CCA rates, the financial analysis assumes all customers are enrolled at the same time and that the implementation phase costs are financed via start-up loans.

In addition to paying the CCA's power supply rate, CCA customers would pay the SDG&E delivery rate and non-bypassable charges. These non-bypassable charges include: 1) Department of Water Resources Bond Charge (DWRBC), 2) Ongoing Competition Transition Charge (CTC), and 3) Power Charge Indifference Adjustment (PCIA). The DWRBC and CTC are charged to SDG&E's bundled customers in the SDG&E delivery charge. It is therefore assumed that the CCA customers would pay these charges as part of the delivery charges, as well. As such, the only additional non-bypassable charge that is payable to SDG&E by a VSME Partner CCA is the PCIA.

6.2.1 Power Charge Indifference Adjustment

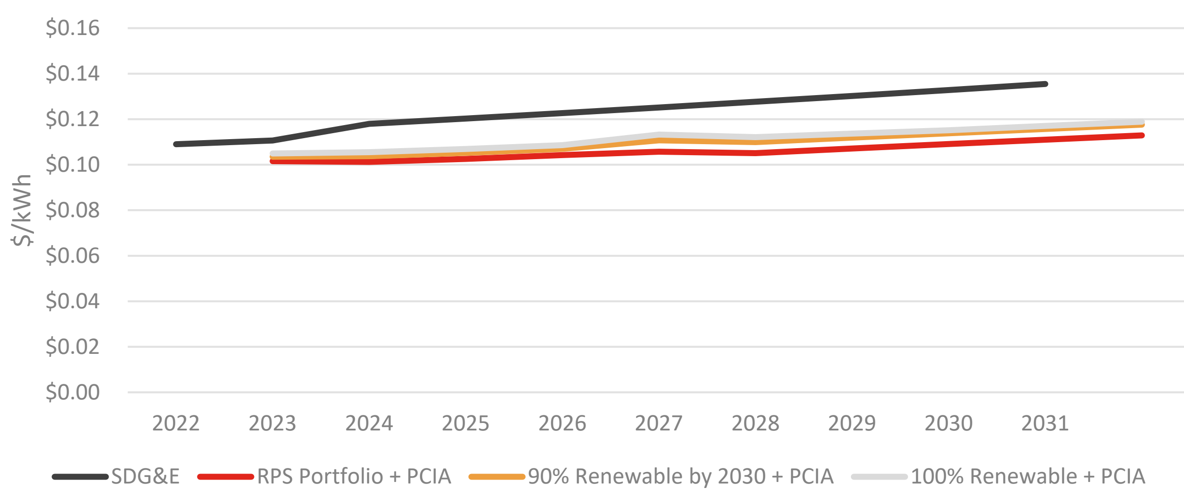
The PCIA is an exit fee that is added to CCA accounts to cover an IOU's stranded costs associated with energy purchases made to anticipated, but unrealized, demand. IOUs enter long-term power contracts anticipating load growth; however, with direct access and CCA programs, a significant share of SDG&E's loads will be unbundled by 2023.

With a launch date of April 2023, the VSME Partner CCA customers would pay the 2022 PCIA vintage rate. The 2022 vintage PCIA will first be set in Q4 of 2021 and be effective January 1, 2022. The rate will then be updated in fall of 2022 for the 2023 calendar year. Because the rate will not be set for some time, the 2021 Vintage rate is used to forecast the 2022 vintage rate in 2023. The forecast considers the balancing accounts and adjustments made for the 2021 calendar year. The system PCIA rate averages $0.02 in 2023 and increases 5% per year after. These assumptions are conservative as it is more likely that the PCIA will decrease within the 10-year timeframe. SDG&E reports that over 1,200 MW in contracts will expire by 2030.[32] Section 8 of this study discusses the risks associated with the PCIA.

6.3 RETAIL RATE COMPARISON

Based on the CCA's projected power supply costs, PCIA, operating costs, and SDG&E's power supply and delivery costs, forecasts of CCA and SDG&E total rates are developed. The analysis balances the rate discount, collection of reserves, and the share of renewable and GHG-free resources purchased. If the discount is too high, the CCA will not be able to collect sufficient reserves to meet reserve targets within the first 5 years. If it is assumed that the CCA will purchase 100% renewable energy, then rates will have to be set close to SDG&E's rates in order for the CCA to collect sufficient revenues to meet costs and reserve requirements. Figure 7-1 compares the forecast SDG&E generation rate with generation costs for the CCA under each power supply portfolio option plus the PCIA. Figure 6-1 illustrates that there is an opportunity for the CCA to offer lower rates while collecting reserves and offering programs.

FIGURE 6-1. AVERAGE GENERATION COST COMPARISON



[32] SDG&E 2020 IRP Appendix 2. Table 2-1 page 9.

A financial pro forma in support of these rates is available in Appendix A. As noted above, there is a viable business case for a VSME Partner CCA. Given this feasibility, the balance of this Study will complete the Business Plan scope. The Business Plan will address the environmental, economic, risk, and governance options associated with a VSME Partner CCA.

7 Environmental and Macroeconomic Impacts

This section provides an overview of the potential environmental and macroeconomic impacts to San Diego County from the implementation of a VSME Partner CCA. In addition, potential future programs that could be offered by a VSME Partner CCA are outlined.

7.1 IMPACT OF RESOURCE PLAN ON GREENHOUSE GAS (GHG) EMISSIONS

According to SDG&E's power content label, SDG&E's resource mix is 43%[33] renewable. While SDG&E reports a large share of renewable energy, some of this share is due to SDG&E's accounting of unbundled RECs. These RECs are not considered GHG free, and when they are excluded, it reduces SDG&E's renewable energy share to 31%.[34] This Study evaluated a VSME CCA assuming that all RPS qualifying resources would be GHG free resulting in portfolios that would significantly reduce the GHG emissions compared with continued service from SDG&E. Through a CCA program, the VSME Cities could choose to offer 100% GHG free power and reduce emissions by at least 890,000 metric tons over the study period compared with continued service from SDG&E. This reduction in GHG emissions was estimated based on SDG&E's most recent IRP filing, and are considered conservative. Additionally, a CCA program would have full control over its power supply portfolio. CCAs have historically set portfolio goals and have been able to achieve those goals while offering competitive rates. If the VSME Cities choose to continue bundled service through SDG&E, the options for achieving GHG-free power supply prior to state mandates will be limited. Currently the state requires that zero-carbon (Clean Energy) resources supply 100% of all retail sales of electricity to California end-use customers no later than December 31, 2045 (Senate Bill 100).

7.2 LOCAL RESOURCES/BEHIND THE METER CCA PROGRAMS

The CCA would 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 install small renewable generation facilities (net energy metering), purchasing from small local for-profit renewable generators (feed-in tariffs), purchasing renewable resources directly, and supporting electric vehicle use. The VSME Partners can identify other program goals in the areas of: building energy efficiency and electrification, energy efficient construction, clean energy transportation enhancement, and energy storage. CCAs are a viable mechanism for developing and implementing these types of programs using funding from a variety of sources, including CCA operating revenues, the CPUC, and the California Energy Commission (CEC).

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[33] 2018 SDG&E Power Content Label.

[34] Elmer, MacKenzie. SDG&E Walks Back Claim it Delivers 45 Percent Renewable Energy. Voice of San Diego May 3, 2021. Available at: https://www.voiceofsandiego.org/topics/news/sdge-walks-back-claim-it-delivers-45-percent-renewable-energy/

Each of these programs also yields economic development benefits by stimulating spending locally and reducing costs for local customers. Economic development can also be accomplished by providing additional support for low-income customers or extra support for new or growing businesses. The following sections discuss these programs in further detail.

7.3 ECONOMIC DEVELOPMENT RATE INCENTIVE

There are several programs that CCAs can offer to stimulate local economic development in their service area. One is a special economic development rate to encourage job providers to locate within the CCA jurisdiction.

Another type of program that promotes economic development is one that provides incentives for businesses to locate in the service area, remain there, or expand. For instance, the CCA could offer rebate programs or fund infrastructure costs for a business to target the business sectors of interest to their service area. For example, if a large industrial customer would like to locate within the CCA service area, increased efficiency may result in decreased costs to all other customers due to overhead cost sharing, allowing an incentive to be paid to the new industrial customer.

7.4 NET ENERGY METERING (NEM) PROGRAM

The CCA could 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, energy storage, demand-side management, energy efficiency, demand response, and electric vehicle charging. The CPUC is currently piloting programs for these DERs where actual savings and system benefits are measured through customer meters rather than using DER equipment modeling. NEM programs allow energy customers who generate some or all of their own power and sell excess generation to the grid to accrue credit, all while inherently providing additional grid supportive services such as volt/var support, frequency regulation, and transmission and distribution line-loss reduction.

SDG&E currently offers a NEM program for solar generation 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 (when solar energy generation is highest) with charges accrued in the winter (when solar generation is lower, and customers rely more on SDG&E's bundled service). Customers earn power credits at the value of electricity and the value of renewable energy credits, 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, as excess generation supplied to the grid 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.[35] All of these CCA-managed NEM programs offer greater incentives than IOUs for customers in their service area to invest in more and larger

[35] https://pioneercommunityenergy.ca.gov/home/nem-solar/, https://www.poweredbyprime.org/faq, http://www.applevalley.org/home/showdocument?id=18607

Distributed Energy Resources. Higher incentives up to the full retail rate have been offered. 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. A VSME Partner CCA would have the option to implement a similar NEM program and the ability to stimulate local economic development in the form of new DER system investments and associated business activity.

7.5 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 solar shade structures in parking lots. In developing a FIT program of its own, the VSME Partner CCA could incentivize customers in their service area to develop local renewable resources.

7.6 LOCAL GENERATION RESOURCES DEVELOPMENT

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

7.7 ELECTRIC VEHICLE (EV) PROGRAMS AND CHARGING STATIONS

Encouraging electric vehicle use can both increase load serving entity (LSE) total load and reduce greenhouse gas emissions within its service area. Many LSEs offer special rates for electric vehicle charging. SDG&E offers two non-tiered, time-of-use (TOU) plans for electric vehicle charging, EV-TOU-2 and EV-TOU-5, that combine the load of vehicle charging with the load of the residence. The two programs offer different TOU periods. EV-TOU customers install a separate meter explicitly for vehicle charging,[37] and 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 than PG&E, the incumbent IOU.[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] Sonoma Clean Power (SCP) also provided qualified customers with incentives to purchase EVs in 2016 and

[36] https://www.mcecleanenergy.org/wp-content/uploads/2017/11/MCE-2018-Integrated-Resource-Plan-FINAL-2017.11.02.pdf

[37] https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans

[38] https://www.mcecleanenergy.org/electric-vehicles/

[39] http://www.siliconvalleypower.com/Home/Components/News/News/5036/2065

continued the program in 2017.[40] A VSME Partner CCA could invest in similar projects to promote electric vehicle use within its service area.

7.8 LOW INCOME PROGRAMS

SDG&E offers assistance to low-income customers on both one-time and long-term bases. For customers in need of sustained assistance, SDG&E offers rates that are up to 30% 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 a 30-35% discount on electric utility bills on households that are at or below 200% 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 SDG&E low-income programs, would continue to be available to CCA customers through SDG&E.

In addition, the Family Electric Rate Assistance (FERA) Program provides 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) oversees a federal program, Low-Income Home Energy Assistance Program (LIHEAP), which offers support for heating, cooling, and weatherproofing homes. Further federally assisted programs managed by the state offer home weatherization assistance for qualifying low-income customers.

7.9 ECONOMIC IMPACTS IN THE COMMUNITY

The analyses contained in this Study for the formation of a VSME Partner CCA have focused only on the direct economic effects of this formation. However, in addition to direct effects, indirect macroeconomic effects are also expected.

The indirect effects of creating a CCA include the effects of increased commerce and disposable income. Within this Study, an input-output (IO) analysis is undertaken to analyze these indirect effects. The IO model estimated the impact on the economy of forming a CCA that would lead to lower energy rates for CCA customers. Three types of indirect 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). The CCA may choose to invest in local DER generation projects in the form of behind the meter or community projects where several customers participate in a centrally located project (e.g. "community solar"). Demand for local renewable resources resulting from these projects would lead to an increase in the manufacturing and installation of DER, along with an increase in employment in the related manufacturing and construction sectors.

[40] https://sonomacleanpower.org/sonoma-clean-power-launches-ev-incentive-program/

[41] https://www.sdge.com/residential/pay-bill/get-payment-bill-assistance/assistance-programs

Increased Disposable Income – Establishing a CCA could 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. Increases in spending would in turn 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 would occur. These may be environmental, such as improved air quality or improved human health due to the CCA 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 Study, reductions in these emissions are captured in indirect effects projected by the models to the extent that carbon prices are accounted for in the input-output matrix.[42]

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. Table 7-2 shows the effect of $9.3 million in rate savings could have on the county economy as estimated in the County of San Diego IMPLAN model.[43] The $9.3 million rate savings represents the minimum annual bill savings projected to occur once the CCA has achieved full operation if all of the load is included (SDG&E-Equivalent Renewable portfolio or 90% Renewable by 2030). The IMPLAN model is an 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.

[42] Decreased health care costs have been modeled to make a major contribution to the local economy. e.g., DT Shindell, Y. Lee & G. Faluvegi, Climate and health impacts of US emissions reductions consistent with 2 °C; *Nature Climate Change* **volume 6**, pages 503–507 (2016)

[43] http://www.implan.com/

This Study uses Value Added and Employment figures to represent the total additional economic impact of the rate savings associated with CCA formation.

The projected 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. Estimated household income distribution is based on the income percentiles from the County-wide statistical atlas.[44] The change in household income assumes that all households are impacted proportionately; however, in practice lower income households typically see the most significant benefit due to the disproportionate amount of total household income that goes to costs associated with household electricity 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 overall impacts of rate savings are likely underestimated.

Table 7-1 details the macroeconomic impacts anticipated from the generation rate savings after forming the CCA. The total output for one year of rate savings is estimated at $13.5 million. In addition, the rate savings are estimated to produce an additional 113 full time jobs.

TABLE 7-1. POTENTIAL ECONOMIC IMPACTS FROM RATE SAVINGS[1]

Impact Type	Employment	Labor Income	Total Value Added	Output
Direct Effect	52	2,556,000	2,592,000	4,767,000
Indirect Effect	10	663,000	1,074,000	1,798,000
Induced Effect	48	2,349,000	4,285,000	6,936,000
Total Effect	113	5,567,000	7,950,000	13,501,000

1. Based on $9.3 million in rate savings per year. The full impact to the County is estimated, though, it can be expected that a large share of these impacts would be realized across the entire VSME Partner CCA service territory.

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

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

8 Sensitivity and Risk Analysis

The economic analysis provides a Base Case scenario for forming a CCA. The Base Case is predicated on numerous assumptions and estimates that influence the overall results. This section of the Study 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 Study. In addition, this section will address uncertainties that should be addressed and mitigated to the maximum extent possible.

8.1 NO ACTION OPTION REVIEW

Prior to engaging in the Sensitivity and Risk analysis, it is important to also assess the option to not proceed with a CCA. Under this option, the VSME Partners may elect to not move forward at this time and possibly reconsider at a later date. This would leave the VSME Partners' customers with SDG&E service and there would be no further action to take at this time.

Reasons for pursuing this option may include avoiding any risk to the VSME Partners from a CCA, keeping the VSME Partners out of the energy procurement business—which is not a core function for many cities, avoiding concerns that SDG&E or the CPUC could change legislative rules that impact future costs making CCA operation more difficult, or determining that the VSME Partners and other local agencies lack sufficient technical experience to set-up and manage a CCA or JPA. Risks to a VSME Partner CCA are described in more detail in Table 8-1.

Risks in pursuing the no action option include missing the opportunity to negotiate favorable terms in a JPA partnership other jurisdictions. Without a CCA, customers located in the cities would not have a choice in their power supply, and they could miss out on potential program benefits discussed in the previous chapter such as NEM, energy efficiency programs, or electric vehicle programs.

8.2 CCA RISK ANALYSIS

The following analysis is an overview of risks and their relative severity, followed by a discussion of each factor. For variables where uncertainty 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.

When evaluating risks, it is important to note that power supply costs are approximately 60% of the total costs, SDG&E non-by-passable (PCIA/CTC) charges account for 30%, and operating costs and reserve contributions account for 10% of total CCA revenue requirement. Figure 8-1 illustrates this breakdown of CCA costs. Table 8-1 provides discussion of each risk factor.

FIGURE 8-1. GENERATION RATE COMPARISON 90% RENEWABLE BY 2030 PORTFOLIO

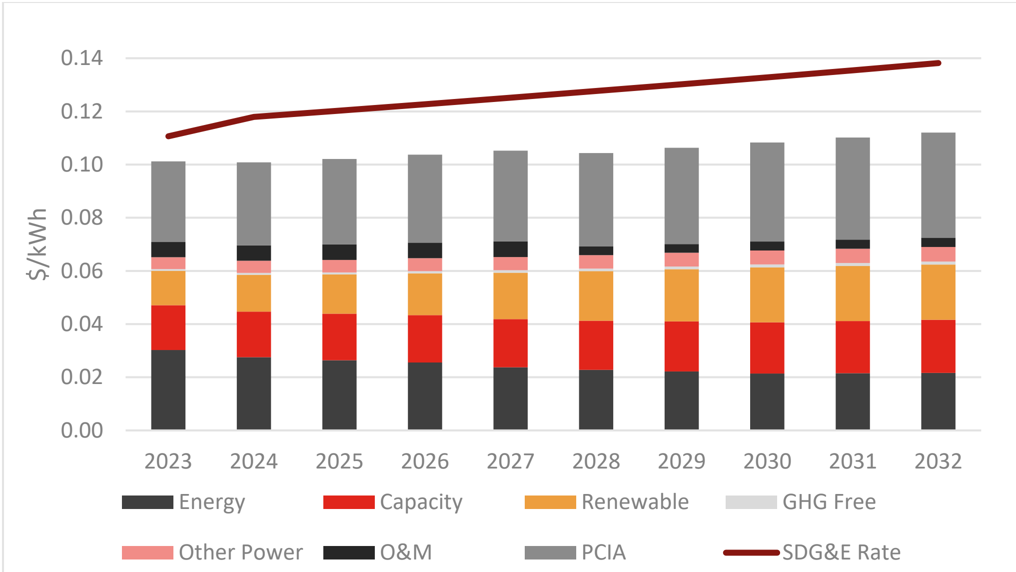


TABLE 8-1. UNCERTAINTY AND MITIGATION STRATEGIES

	Risk	Description	Problem	Mitigation Strategy	Likelihood of Problem	Severity of Problem	Potential to "Suspend" CCA
1	SDG&E Rates and Surcharges	SDG&E's generation rates decrease or its non-bypassable charges (PCIA/CTC) increase	• CCA rates exceed SDG&E • Increased customer opt-out rate	• Establish Rate Stabilization Fund • Invest in a balanced energy supply 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 been able to buffer rate impacts using financial reserves, then adjust power supply to regain rate advantage.	Medium – CCAs may need to rely on reserves to manage short-term fluctuations.
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 to advocate for CCA	Low – existing regulatory precedent and a growing market share 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.	Medium – energy policy severe enough to make CCA infeasible is not likely.
3	Power Supply Costs	Power prices increase at crucial time for CCA	• CCA rates exceed SDG&E • Increased customer opt-out rate	• Long-term contracts • Draw on CCA reserves to stabilize rates through price spike	Low – market prices are unlikely to spike enough to make 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 CCA to dig into reserves or delay launch.	Low – CCA and IOU face the same market for power.
4	SDG&E RPS Share	SDG&E's RPS or GHG-free power portfolio grows to match or exceed CCA's	Increased customer opt-out rate	• Increase renewable power portfolio • Emphasize rates and local programs in marketing	Medium – SDG&E's power portfolio is dynamic and could change rapidly as a result of other CCA departures.	Low – CCA would have capability to increase renewable energy purchases to match or exceed SDG&E if the event occurs. In addition, CCA would promote other benefits of its service to customers.	Very Low – CCA is likely to respond effectively if this occurs.

	Risk	Description	Problem	Mitigation Strategy	Likelihood of Problem	Severity of Problem	Potential to "Suspend" CCA
5	Availability of RPS/GHG-free power	Unexpectedly high market demand or loss of supply of renewable resources	• 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 are projecting a plethora of RPS and GHG-free bids available on the market.	Medium – if 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.	Low – negligible chance of occurring.
6	Financial Risks	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, such that financing is almost certainly available.	Medium – in the event CCA is limited in financing options, it can adopt a more conservative program design and gradual roll-out.	Low
7	Loads and customer participation	Unprecedented opt-out rate reduces competitiveness Net Zero homes	• Excess power contracts • Poor margins	• Increase marketing • Reduce overhead • Expand to new customer markets • Consider merging with existing CCA • Consistent CCA rate review	Low – as CCAs have become more common in California, and CCA marketing firms have become more experienced, opt-out rates have declined. Current saturation of net zero or NEM customers is low	Low – CCA would have numerous viable options in the event they suffer unexpectedly low participation.	Low
8	Direct Access Changes	CPUC opens DA to a broader customer base and the CCA loses commercial load	• Excess power contracts • Lower margins	• County loads are >50% residential • Charge exit fee to departing loads after 60 day opt-out notice issued	Low – CPUC has discussed opening up DA to all non-residential, but have only slowly increased the cap.	Low – with the large customer base in unincorporated county, a VSME Partner CCA is feasible even without commercial accounts.	Low

The various sensitivities are discussed below followed by the results of the sensitivity analysis.

8.3 SDG&E RATES AND SURCHARGES

Sensitivity analyses were conducted for two components of SDG&E rates: generation rate and the PCIA. Delivery rates are paid by both CCA and SDG&E bundled customers. As such, changes in delivery rates impact all customers equally.

8.3.1 Generation Rate

SDG&E generation rates are projected to increase on average by 2% per year over the next 10 years based on the projected market prices, SDG&E's current resource mix and future requirements. To explore the impact in the case that SDG&E's generation rate changes significantly relative to the CCA's generation cost, SDG&E's generation rates and power costs are modeled in the high and low case by incorporating higher (3%) and lower (-1%) generation rate growth rates.

8.3.2 PCIA

When legislation was introduced to allow the formation of CCAs, it was recognized that the IOUs currently serving the potential CCA customers might 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 its calculation and the fact that the PCIA level is variable and contains a great amount of uncertainty.

The level of the PCIA, or other non-bypassable charge that will potentially replace the PCIA, would impact the cost competitiveness of the VSME Partner CCA. In order to be competitive, the CCA's power supply costs plus PCIA and other surcharges must be at or lower than SDG&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 SDG&E from departing load. Uncertainties surrounding the PCIA include methodology assumptions unique to SDG&E, as well as to what degree previously acquired power contracts can be retired. The potential for the PCIA to increase sharply occurs when SDG&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 SDG&E's own resources and signed contracts obtained prior to load departure; once those contracts expire, the related PCIA would disappear. The PCIA would therefore vary over time, but it is expected that it would decline as market prices increase and grandfathered contracts expire.

The uncertainty associated with forecasted PCIA rates is modeled considering historic PCIA increases as well as the adopted methodology used for the PCIA calculation (October 11, 2018) and proposed changes currently ongoing within the new rulemaking process. In addition to the base case, low and high PCIA forecasts are modeled. High PCIA rates have historically not been maintained and often become implemented as a result of the accounting and rate setting process the IOUs go through each year. The PCIA rate will also vary by vintage where some vintages may see large temporary rate increases while other vintages may experience rate reductions. A high PCIA rate scenario increases the PCIA by $0.005/kWh above the base case for 3 years. A low PCIA rate scenario is not modeled as it would only inform the additional rate savings available to CCA customers and does not change the result showing program viability.

8.4 REGULATORY UNCERTAINTIES

There are numerous factors that could impact SDG&E's rates in addition to the market price impacts described above. Regulatory changes, plant or technology retirements, inflation, and gas prices could all impact SDG&E's rates in the future. Regulatory issues continue to arise that may impact the competitiveness of a VSME Partner CCA. The impact of these factors is difficult to assess and model quantitatively. However, California's operating CCAs have worked aggressively to address any potentially detrimental changes through effective lobbying at the California state legislature and at the California Public Utilities Commission.

New legislation could also impact a VSME Partner 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 requirements associated with renewable energy procurement. Specifically, CCAs are required to contract 65% of renewable resources for 10 years or more by 2020, and thereafter.

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

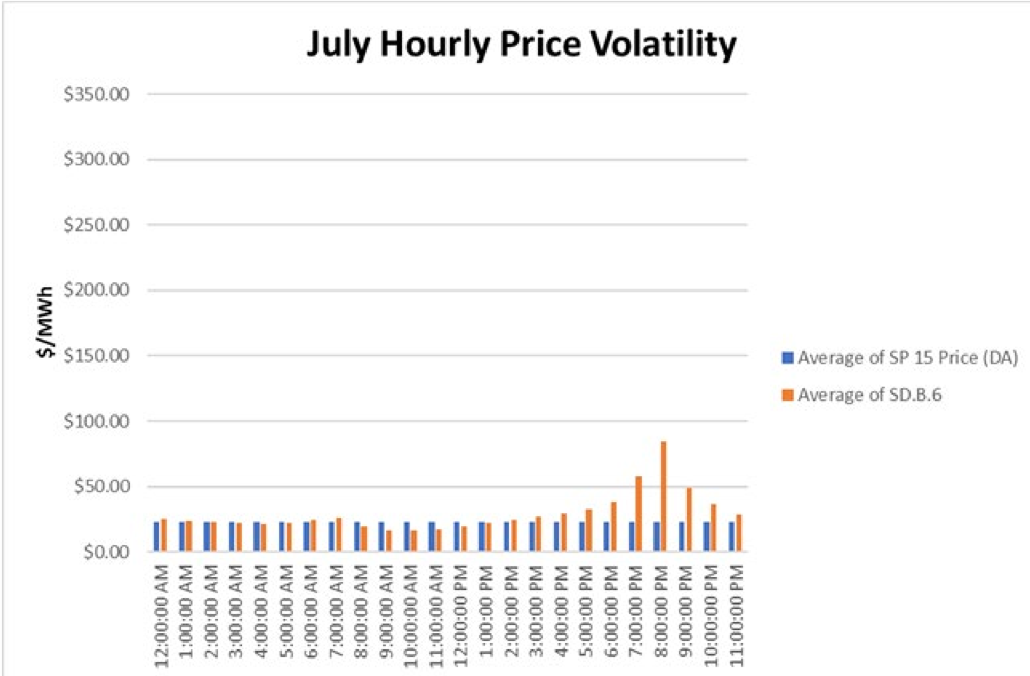
8.5 POWER SUPPLY COST RISK

There are several attributes of CCA power supply costs that introduce uncertainty. The two described in this section include price volatility and weather events and under or over procurement.

8.5.1 Price Volatility

Southern California is becoming increasingly reliant on wind and solar resources which rely on availability of wind and the sun. The increasing distributed generation (DG) saturation has led to regular pricing events in which prices may move $1,000/MWh from one hour to the next, especially during July and August. This volatility occurs as DG generation reaches its peak and again as the sun sets and load remains high. This volatility is difficult to mitigate and is expected to worsen as carbon legislation becomes more aggressive in California. Figure 8-2 shows the average hourly pricing compared to the day ahead pricing for both July and August. Figure 8-3 shows the maximum difference in the same months.

FIGURE 8-2. HOURLY VS. DAY-AHEAD PRICING



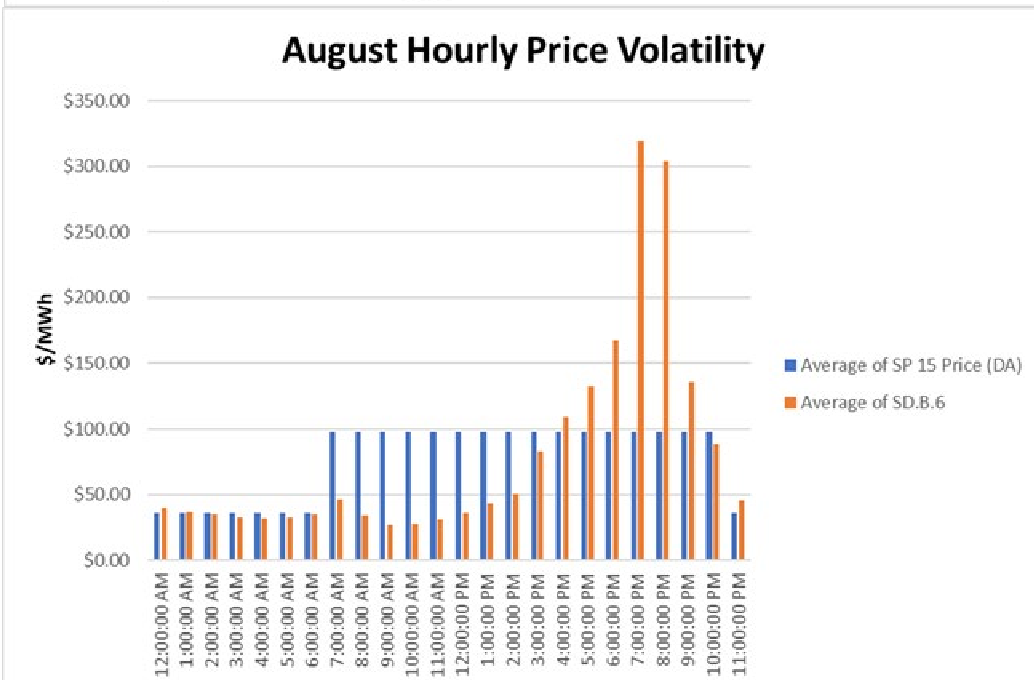
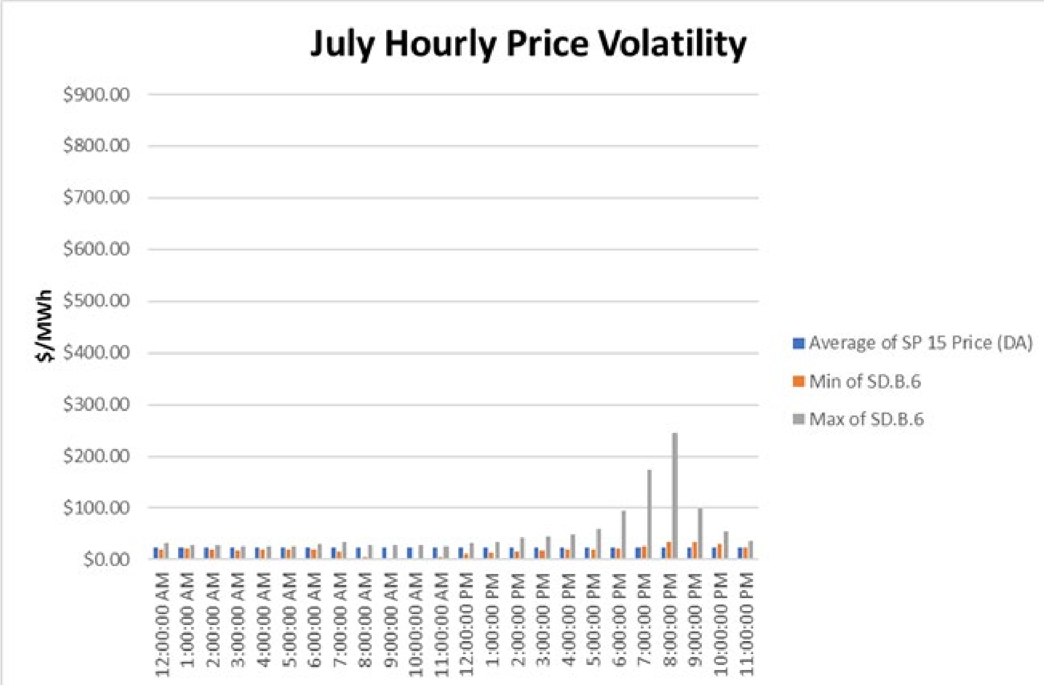
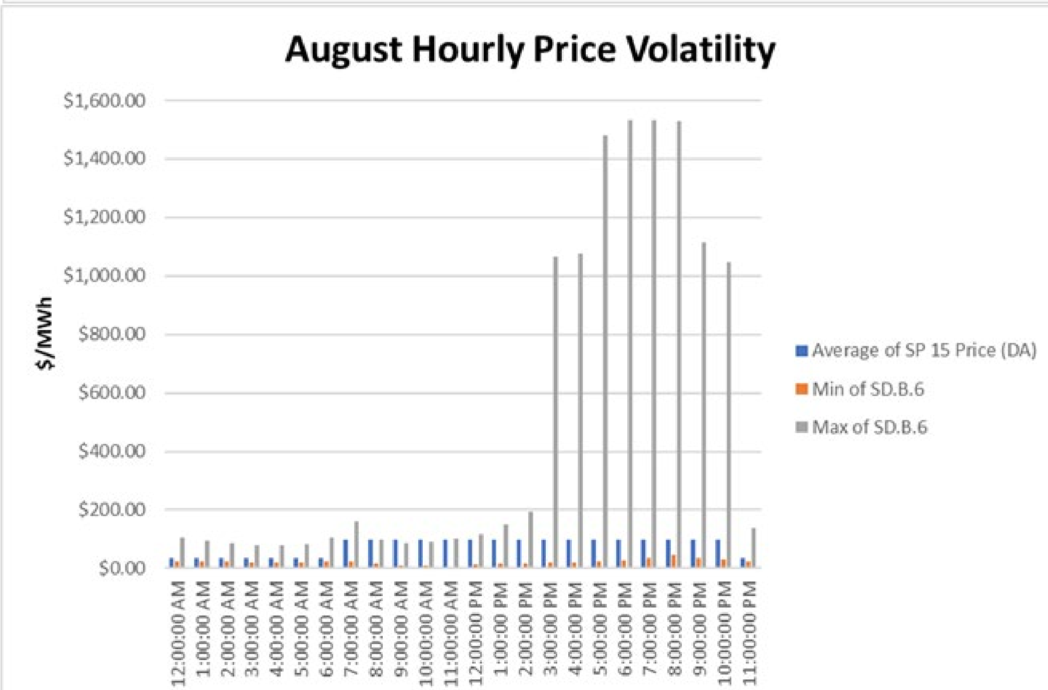


FIGURE 8-3. SUMMER PRICE VOLATILITY





Price volatility can be managed using a battery storage technology or with hourly power supply options. A battery storage option could charge the energy during the lower price periods and use the energy from storage during high price hours and events. A physical option can also be secured to manage the pricing risk associated with these events. A physical option is similar to an insurance policy, in which the CCA would contract with a power supplier to cover CCA loads at a fixed price during high priced periods in exchange for a premium paid to the supplier.

8.5.2 Procurement

Second to price uncertainty, under or over procurement of resources can significantly impact power supply costs. Variance in load forecast and actualized loads can increase power costs if a load serving entity under-procures energy hedges. CCAs must make procurement decisions before knowing how loads will materialize. Program participation, weather, and data inconsistencies can all impact the procurement quantities and resulting market exposure. Additionally, resource development risk can introduce uncertainty in long-term planning. The CCA's portfolio manager is charged with developing a resource strategy to mitigate these risks while meeting California's mandates for renewable energy and technology acquisitions at least cost.

Uncertainty in power costs are modeled such that the entire portfolio is 15% more expensive than forecast. The high case illustrates market exposure during the summer, under procurement and higher than expected power prices. In the low case, the portfolio costs are 10% lower. The low scenario reflects the CCA's ability to procure low-cost high-quality resources (baseload or energy plus capacity products) and lower than expected market prices.

8.6 FINANCIAL RISKS

Starting a new venture carries financial risks that will have to be considered and mitigated 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.

A VSME Partner CCA could 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 SDG&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, thereby minimizing the fixed costs of operating the CCA.

A VSME Partner CCA would need to manage the financial risk associated with power supply costs by managing power market and load exposure through 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 the SDG&E and the other IOUs can be a valuable guide for a VSME Partner CCA.

8.7 LOADS AND CUSTOMER PARTICIPATION RATES

The Study 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 Study uses a conservative participation rate of 95% for residential customers and 90% 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, would 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 would increase the fixed costs to a VSME Partner CCA. For reference, recent CCAs have experienced participation rates in the 90-97% range.

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% participation rate for non-residential customers, while the low case assumes the participation rate is reduced by 10% for all customers. The low case assumes a -0.14% growth in energy and customers after 2019, while the high scenario assumes a 1.36% growth in energy and customers.

The experience of existing CCAs suggests that only a small number of customers opt-out. For example, PCE has an opt-out rate of 2%, while CPA has a current opt-out rate of 0.7%. Once a CCA is operating, the number of customers switching back to the incumbent IOU has also been less than 5%. In order to mitigate the potential switching of customers, it would be important for the 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 would lead to strong customer retention.

The CPUC recently increased the cap on DA customers which translates to a very small increase in the number of commercial customers that might not join a VSME Partner CCA. The participation rate for commercial rate classes was adjusted to account for the expected impact of this change. However, if the CPUC decides in the future to open up DA to all non-residential accounts, the VSME Partner CCA could lose nearly half of its load. This possibility is not very likely; however, it is estimated that the number of residential customers could sustain a VSME Partner CCA.

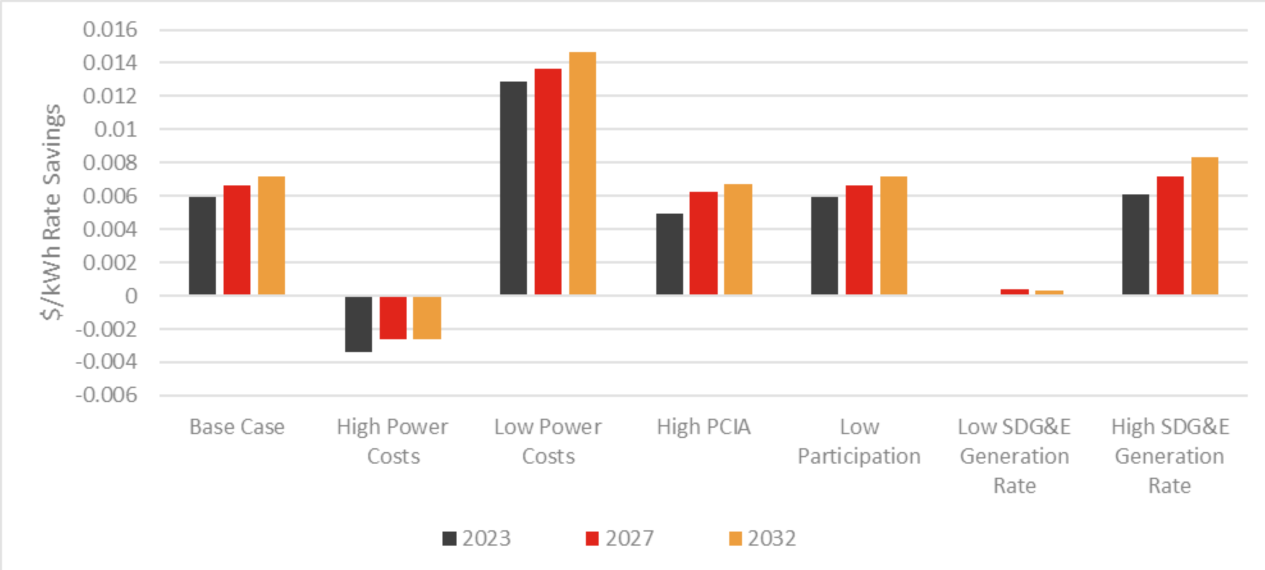
8.8 SENSITIVITY RESULTS

Figure 8-4 provides the results of the sensitivity analysis for the 90% Renewable by 2030 Portfolio. The scenarios assume the following:

- High Power Costs: 15% increase in total power supply costs
- Low Power Costs: 10% lower than forecast
- High PCIA: 25% higher for 3 years
- Low Participation: Program Participation is 80% (vs. 90-95%)
- Low SDG&E Generation Rate: -1% annual change from 2021
- High SDG&E Generation Rate: 3% annual change from 2021

The figure illustrates that the viability of a rate discount is most sensitive to power costs.

FIGURE 8-4. BASE CASE PORTFOLIO SENSITIVITY



While the CCA would not be able to impact SDG&E's generation rates, the CCA does have the opportunity to monitor and actively opine on the costs and methodology used to allocate non-bypassable costs to CCAs in SDG&E's service area, including the PCIA. Given recent history, this task would be shared with other CCAs and is an important and time-consuming task that can mitigate the impact on the CCA's costs. SDG&E's PCIA is at a historic high; however, the design of the PCIA implies that the PCIA will decrease over time as SDG&E's high-cost contracts expire and market prices increase.

This Study assumes a relatively high customer opt-out percentage (10% for non-residential customers) compared to the more modest opt-out rates experienced by California's actively operating CCAs, which is closer to 2-5% overall. While there is a possibility that a VSME Partner CCA does not reach the projected participation rates, careful monitoring and planning can reduce the potential impact of low loads through flexible power supply contracts and regular monitoring of administrative and general expenses.

The CCA should also implement a rate stabilization fund so that short-term events that result in lower SDG&E rates, or higher PCIA rates, can be mitigated with reserves rather than by rate increases. Reserves would help the CCA remain competitive and provide rate stabilization for customers. A rate stabilization reserve account balance equal to 10% of annual revenues would mitigate most rate impacts CCAs have observed to date where CCA costs have been 1-5% higher than the incumbent IOU.

9 CCA Governance Options

The technical feasibility analysis assumes that the VSME Partners form a JPA for purposes of operating A CCA program. This section of the Study further discusses this and other governance options that may be available to the VSME Partners. Rate impacts, timing of launch, staffing organization, and local control aspects of these options are explored. Each CCA governance option is discussed below.

9.1 ENTERPRISE CCA

With this governance option, the VSME Partners form a CCA that functions as a department within the Cities' government structure subject to the direct control of the Board of Supervisors and Cities' administration.

- *Financial Viability*: This option is viable (see Appendix). Based on the analysis in this Study, individual CCAs are economical for all three cities.
  - *Escondido: Power Portfolio is 100% Renewable by 2030 and can offer a 2% discount*
  - *San Marcos: Power Portfolio is 95% Renewable by 2030 and can offer a 2% discount*
  - *Vista: Power Portfolio is 90% Renewable by 2030 and can offer a 2% discount*
- *Governance*: The CCA operates as a city department and is governed by the City Council.
- *Local Control*: Decision-making is totally focused on the needs of the individual cities.
- *Other Attributes*: Operating an Enterprise CCA may require specific measures to protect city general funds from CCA obligations.

Table 9-1 summarizes key metrics for an Enterprise CCA model. All metrics are calculated assuming VSME City financing for pre-launch costs; however, these can also be externally financed. Working capital assumes each VSME City meets its respective CAP goals.

TABLE 9-1. ENTERPRISE CCA MODEL METRICS

Pre-Launch Costs for Each City	$600,000
Working Capital & Collateral	Escondido: $9 million San Marcos: $9 million Vista: $9 million
Estimated Bundled Rate Discount	2%
Power Supply Cost Allocation	Power supply obtained under direct control of each city

Another permutation of an Enterprise arrangement could be to form a JPA for shared overhead expenses with other CCAs. In this study, this operating arrangement is referred to as the Enterprise JPA. Each VSME City would form a standalone CCA and then join other independent CCAs to form a JPA that shares some of the administrative costs and possibly a common power and data management vendor. In this case, each CCA maintains control over the makeup of its power supply portfolio. This option therefore maintains local control over power supply and rates. There are some costs that would likely not be shared such as regulatory filings, CAISO-related expenses, and portfolio modeling and risk management.

9.2 VSME PARTNER JPA CCA

Under the VSME Partner JPA CCA, the VSME Partners establish a CCA that includes one or more other jurisdictions. This structure implies shared decision-making rights in accordance with a specified voting structure. Additionally, under a JPA CCA model, administrative and consultant costs are pooled and covered by the collective JPA CCA revenues.

- *Financial Viability*: This option is viable even if each VSME City has a different portfolio supply mix, or should other cities join the JPA at the same or different portfolio supplies. There are lower administrative costs compared with Enterprise CCA governance or Enterprise JPA organizational structure.
- *Governance*: The VSME Partners would establish the governing board. Having a limited number of board members helps to enable flexible governance and maintain focus on local control.
- *Local Control*: The VSME Partners share decision making with other members.
- *Other Attributes*: Potential partners should share the VSME Partners' intentions for CCA goals, local programs, and operations design. Operational savings on non-power supply costs (administration, legal, regulatory, and other services) would likely occur due to economies of scale. A JPA agreement provides express financial protection of jurisdiction general funds from CCA contractual obligations.

Table 9-2 details estimated start-up costs for a VSME Partner JPA.

TABLE 9-2. VSME PARTNER JPA CCA MODEL METRICS

Pre-Launch Costs	$600,000
Working Capital & Collateral	$18 million
Estimated Bundled Rate Discount	2%
Power Supply Cost Allocation	Power supply obtained for all members but can accommodate special requests such as 100% Renewable options. Different power supply portfolio costs can be allocated to each member city.

9.3 SAN DIEGO COMMUNITY POWER

This JPA would likely accept new members with future launch dates. Membership may require upfront financial commitments from the VSME Partners to cover the cost of filing a new implementation plan and any additional working capital needs.

- *Financial Viability*: This will be the largest CCA in SDG&E service territory and will likely provide the greatest potential for economies of scale savings in overhead expense.
- *Governance*: When the Board of Directors becomes large, decision-making is often delegated to committees. Risk sharing is greatly reduced as the size of the JPA increases considerably. Each City's vote and local control may be impacted if based on weighted voting instruments.
- *Local Control*: As part of a larger CCA with a greater number of board members, each City's relative voice becomes a smaller share. As of yet, this CCA includes only 5 cities, but could be expanded to include many more.
- *Other Attributes*: Due to the size of this CCA, and the proposed launch of 2023, SDCP may have already accrued a large share of its working capital and reserves by the time service would begin to the Cities. In this case, it is possible that the VSME Partners' financial obligation for reserves and start-up capital would be greatly reduced compared with the other two options discussed so far. In addition, the VSME Partners could reduce pre-launch costs by up to $600,000 plus avoid the CPUC bond commitment of $147,000 and the CAISO deposit of $500,000.

Table 9-3 shows that the start-up costs borne by the cities is uncertain at this time, but that the likelihood of higher rate savings is high given the size of SDCP.

TABLE 9-3. VSME CITIES JOIN SDCP

Pre-Launch Costs	TBD: Based on offer from SDCP
Working Capital	TBD: Based on offer from SDCP
Estimated Bundled Rate Discount	Not available
Power Supply Cost Allocation	TBD, Current rates are 50% renewable with 5% additional GHG free power
Launch Date	Potentially as early as 2023

9.4 CLEAN ENERGY ALLIANCE (CEA)

As with SDCP, this JPA would likely accept new members with future launch dates. Membership may require upfront financial commitments from the VSME Partners to cover the cost of filing a new implementation plan and any additional working capital needs.

- *Financial Viability*: Joining CEA is likely technically feasible as there would be economies of scale savings beyond what the three VSME Partners could obtain by themselves. This JPA will likely remain smaller in size compared with SDCP, since the City of San Diego, founding member of SDCP, is a significant share of regional loads.
- *Governance*: The three member cities in CEA are roughly the same size as the VSME Partner Cities. Therefore, it is likely that governance by a JPA board would not be significantly impacted by a doubling CCA size in the number of members as well as the load served.
- *Local Control*: The current size of this JPA is three jurisdictions. Even if all three Cities join, the six-member Board is a still a manageable size.
- *Other attributes*: CEA will have been operating for 1-2 years by 2023, the proposed launch date for the VSME Partners. In addition to the collection of operating reserves, CEA will already have contracts in place reducing star-up costs for the VSME Partners. Together, the VSME Partners could reduce pre-launch costs by up to $600,000 plus to avoid the CPUC bond commitment of $147,000 and the CAISO deposit of $500,000 as shown in Table 9-4.

TABLE 9-4. VSME CITIES JOIN CEA

Pre-Launch Costs	TBD: Based on offer from CEA
Working Capital	TBD: Based on offer from CEA
Estimated Bundled Rate Discount	Not available
Power Supply Cost Allocation	TBD, Current portfolio considered includes 50% renewable with up to 75% total GHG free power
Launch Date	Potentially as early as 2023

9.5 SUMMARY OBSERVATIONS ON GOVERNANCE OPTIONS

If the VSME Partners move towards CCA adoption, it should further investigate each of these governance options. EES recommends that the VSME Partners further discuss the options to consider the respective pros and cons. The VSME Partners should develop a more detailed assessment of the options of joining existing organizations or developing new, local/regional organizations.

9.6 CCA OPERATIONAL OPTIONS

If the VSME Partners operate as a JPA, there are several staffing options available. One option would be to operate the CCA with minimal staff, such as a General Manager, Power Supply Manager, and Customer Service Manager, to oversee consultants that would perform all necessary technical tasks. Another option is to minimize the use of outside consultants and hire sufficient staff in-house to manage all necessary tasks. Most operating CCAs have started with minimal staffing and then transitioned over time to additional staff in-house. A third option is to have an independent third party completely operate the CCA.

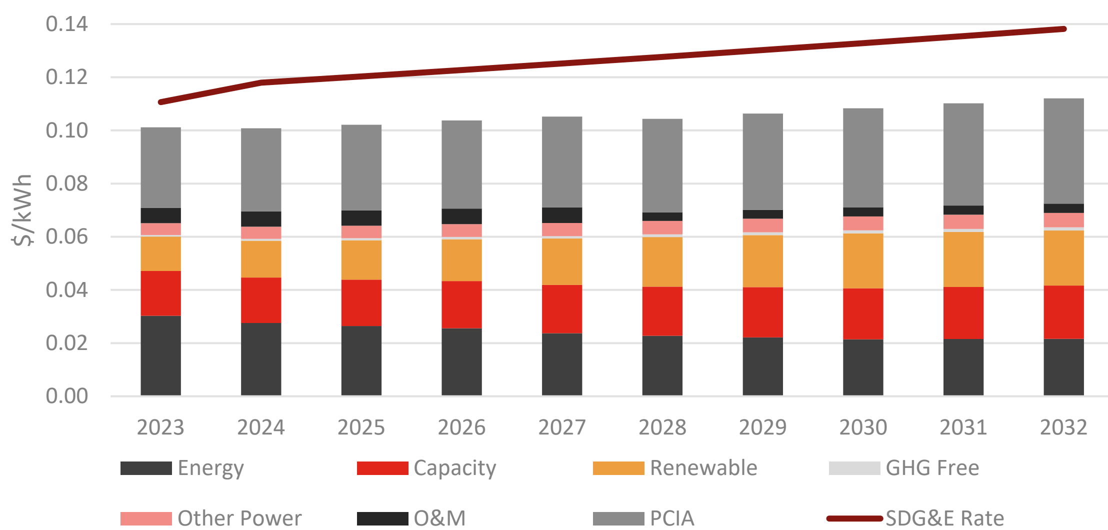
For this Study, it is assumed that the VSME Partners would operate a CCA with limited staff supported by consultants experienced in power procurement, data management, and utility operations. If the VSME Partners decide to transition some administrative and operational responsibilities to internally staffed positions, the CCA could reach a full-time staff of approximately 4 employees to perform its responsibilities, primarily related to program and contract management, legal and regulatory, finance and accounting, energy efficiency, marketing, and customer service. Technical functions associated with managing and scheduling power suppliers and those related to retail customer billing would likely still be performed by an experienced third-party consultant.

10 Conclusions and Recommendations

The first impact associated with forming a VSME Partner CCA would be lower electricity bills for VSME Partner CCA customers. CCA customers should see no obvious changes in electric service other than the lower price and more renewable power procurement, consistent with the VSME Partner city CAP goals. Customers would pay the power supply charges set by the CCA and no longer pay the costs of SDG&E power supply but would still pay the costs of SDG&E distribution.

Given this Study's findings, the CCA can establish a goal of providing rates that are equal to or lower than the equivalent rates offered by SDG&E even under the 90% Renewable by 2030 Portfolio option. The projected CCA and SDG&E rates are illustrated in Figure 10-1.

FIGURE 10-1. RATE COMPARISON



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

10.1 LOCAL CONTROL

A second outcome of forming a CCA is that the CCA can help the member cities meet their CAP renewable energy target. The cities CAP goals are 90%, 95%, and 100% renewable electric supply by 2030 for Vista, San Marcos, and Escondido respectively. Achievement of these CAP goals are under the total control of the VSME Partners under the CCA business model.

10.1.1 Energy Programs

A third outcome of forming a CCA would be an increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by SDG&E are not expected to change as a result of forming a CCA (i.e., they would still be available). The CCA customers would continue to pay public goods charges-which fund energy efficiency programs for all customers, regardless of supplier—to SDG&E. The energy efficiency programs ultimately planned for the CCA would be in addition to the level of investment that would continue in the absence of a CCA. Thus, the CCA has the potential to increase energy investment and savings while further reducing emissions through expanded energy efficiency programs.

10.2 FINDINGS AND CONCLUSIONS

Based on the analysis conducted in this Study, the following findings and conclusions are made:

- The formation of a CCA is technically and financially feasible and could yield benefits for all participating residents and businesses.
- Financial benefits include electric retail rates that are 2% lower compared with SDG&E rates.
- Benefits are also achieved through local decision-making about power supply, rates, and customer programs. Specific programs could include economic development incentives and targeted energy efficiency and demand response programs. CCA start-up costs could be fully recovered within the first five years of CCA operations.
- After this cost recovery, revenues that exceed costs could be used to finance a rate stabilization fund, new local renewable resources, economic development projects, and/or lower customer electric rates.
- The sensitivity analysis shows that the ranges of prices for different market conditions will for the most part not negatively impact CCA rates compared to SDG&E rates. Where negative impacts may exist, risks can be mitigated.
- The CCA could be a means to achieve local control of energy supply, and to help the Cities achieve their CAP measures to reduce GHG emissions.
- There are risks associated with a VSME Partner CCA. If formed, this will be a new and competitive effort for the Cities. New skill sets and strong policy guidance will be needed for a VSME Partner CCA to succeed.

If the relative impacts of a CCA for the VSME Partners and their residents persuade the VSME Partners to form a CCA, the VSME Partners should consider the following next steps: select a governance option, begin pre-startup operations, and develop and file an Implementation Plan.

10.3 SUMMARY AND NEXT STEPS TIMELINE

This Study concludes that the formation of a VSME Partner CCA is technically and financially feasible and could yield benefits in excess of costs for all participating residents and businesses. These benefits are summarized in Table 10-1 below and could include lower rates for electricity.

TABLE 10-1. KEY CCA STATISTICS

Power Supply Portfolio Scenario:	VSME Partner CCA : 90% Renewable Portfolio	City of Vista Enterprise CCA: 90% Renewable Portfolio	City of San Marcos Enterprise CCA: 95% Renewable Portfolio	City of Escondido Enterprise CCA:100% Renewable Portfolio
2024 Operating Budget, $ million	$105	$31	$31	$46
2024 Revenues, $ million	$118	$32	$32	$50
2024 Load Served, GWh	1,527	484	431	666
Startup Loan (Including Pre-Startup Costs and Working Capital, Collateral), $ million	$18	$9	$9	$9
Startup Loan and repayment, years	5	5	5	5
Average Rate Discount, %	2.1%	2.0%	2.0%	2.0%

Table 10-2 provides a high-level timeline of next steps for the different governance options. A detailed CCA implementation schedule is provided in the Appendix. This schedule could apply to any new CCA (enterprise or JPA structure).

TABLE 10-2. NEXT STEPS OVERVIEW

	Enterprise CCA	VSME Partner JPA CCA	Join Existing JPA CCA
Select Governance	Form Enterprise Fund.	Draft JPA and obtain at least 1 Partner.	Select Representative for Board. Pass CCA ordinance and sign JPA agreement.
File Implementation Plan	File Implementation plan two calendar years before launch. File in December 2021 for January 2023 launch.	File Implementation plan by December 2021 for January 2023 launch.	Existing JPA would file Implementation Plan in Dec 2021.
Hire Staff	Each city would hire minimum staff (4) to begin pre-start-up operations.	Hire minimum staff to begin pre-start-up operations.	Existing JPA will begin all pre-startup operations. JPA Board makes contract and hiring decisions. Cities may designate a board member depending on JPA agreement.
Secure Financing	Have financing in place to facilitate contracting for power and services.	Have financing in place to facilitate contracting for power and services.	
Contract for Power and Data Management Services	Secure power contracts, Resource Adequacy must be secured before launch.	Secure power contracts, Resource Adequacy must be secured before launch.	
Launch	2023	2023	2023

11 Appendix A – Base Case Pro Forma Analyses

TABLE 11-1. BASE CASE ANNUAL PROFORMA, ALL 3 CITIES, 90% RENEWABLE BY 2030

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Revenues from Operations ($)											
Electric Sales Revenues	$0	$96,192,135	$117,959,710	$120,637,228	$122,693,656	$125,467,388	$128,297,541	$131,184,998	$134,130,640	$137,135,352	$140,200,015
Less Uncollected Accounts	$0	$192,384	$235,919	$241,274	$245,387	$250,935	$256,595	$262,370	$268,261	$274,271	$280,400
Total Revenues	$0	$95,999,750	$117,723,791	$120,395,954	$122,448,268	$125,216,453	$128,040,946	$130,922,628	$133,862,379	$136,861,081	$139,919,615
Cost of Operations ($)											
Cost of Energy	$0	$74,289,743	$96,805,507	$98,156,661	$99,804,425	$104,361,185	$105,973,910	$107,826,378	$109,651,986	$111,339,330	$113,067,274
PCC1	$0	$1,303,186	$1,835,604	$1,974,222	$2,121,756	$6,749,237	$6,540,288	$6,610,695	$6,504,679	$6,675,908	$6,851,645
PCC2	$0	$1,865,757	$2,665,959	$2,898,072	$3,140,245	$3,299,539	$3,465,044	$3,636,975	$3,815,557	$3,915,998	$4,019,083
Resource Adequacy	$0	$18,094,473	$24,243,601	$24,901,083	$25,504,443	$26,170,619	$26,854,195	$27,555,627	$28,275,380	$29,013,933	$29,771,777
CF Requirement	$0	$1,322,036	$1,845,867	$1,966,170	$2,092,785	$2,204,398	$2,320,438	$2,441,059	$2,566,423	$2,633,981	$2,703,318
Miscellaneous CAISO	$0	$4,916,798	$6,674,290	$6,917,141	$7,168,828	$7,357,540	$7,551,220	$7,749,998	$7,954,009	$8,163,390	$8,378,283
LT Renewable Contracts	$0	$22,676,683	$30,743,836	$31,793,738	$32,855,477	$23,385,130	$25,425,473	$26,827,872	$28,633,168	$28,810,693	$28,989,319
Block Energy	$0	$24,110,811	$28,796,350	$27,706,236	$26,920,892	$35,194,722	$33,817,253	$33,004,152	$31,902,771	$32,125,426	$32,353,849
Operating & Administrative											
Billing & Data Management	$0	$1,177,210	$1,608,247	$1,650,583	$1,694,033	$1,738,627	$1,784,394	$1,831,367	$1,879,576	$1,929,053	$1,979,834
SDG&E Fees	$0	$357,428	$441,480	$453,101	$465,029	$477,270	$489,834	$502,728	$515,962	$529,544	$543,485
Consulting Services	$278,333	$957,300	$1,122,714	$985,987	$1,005,707	$1,025,821	$1,046,337	$1,067,264	$1,088,609	$1,110,382	$1,132,589
Staffing	$0	$696,165	$1,096,525	$1,278,369	$1,303,936	$1,330,015	$1,356,615	$1,383,747	$1,411,422	$1,439,651	$1,468,444
General & Administrative expenses	$0	$158,763	$181,238	$163,638	$166,911	$190,649	$184,058	$177,127	$180,670	$204,683	$198,373
Debt Service	$0	$2,977,881	$3,985,605	$3,985,605	$3,985,605	$3,985,605	$0	$0	$0	$0	$0
Total O&A Costs	$278,333	$6,324,746	$8,435,808	$8,517,283	$8,621,220	$8,747,986	$4,861,239	$4,962,234	$5,076,239	$5,213,313	$5,322,725
Total Cost	$278,333	$80,614,489	$105,241,315	$106,673,944	$108,425,645	$113,109,171	$110,835,149	$112,788,612	$114,728,225	$116,552,644	$118,390,001
Net Income from Operations	($278,333)	$15,385,261	$12,482,476	$13,722,010	$14,022,624	$12,107,282	$17,205,797	$18,134,016	$19,134,154	$20,308,437	$21,529,614
Cash from Operations and Financing											
Net Income	($278,333)	$15,385,261	$12,482,476	$13,722,010	$14,022,624	$12,107,282	$17,205,797	$18,134,016	$19,134,154	$20,308,437	$21,529,614
Cash from Financing	$600,000	$17,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cash Available	$321,667	$32,385,261	$12,482,476	$13,722,010	$14,022,624	$12,107,282	$17,205,797	$18,134,016	$19,134,154	$20,308,437	$21,529,614
Available For Reserves	$921,667	$33,306,928	$45,789,404	$59,511,413	$73,534,037	$85,641,319	$102,847,116	$120,981,131	$140,115,285	$160,423,722	$181,953,336
Reserve Targets	$91,507	$26,503,394	$34,599,884	$35,070,886	$35,646,787	$37,186,577	$36,438,953	$37,081,188	$37,718,869	$38,318,677	$38,922,740
Reserve Outlays											
CPUC Bond	$297,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$6,506,534	$4,385,985	$13,251,008	$13,446,722	$10,567,492	$17,953,421	$17,491,781	$18,496,473	$19,708,628	$20,925,552
Total Reserve Outlays	$297,000	$6,506,534	$4,385,985	$13,251,008	$13,446,722	$10,567,492	$17,953,421	$17,491,781	$18,496,473	$19,708,628	$20,925,552
Rate Stabilization Reserve Balance	**$624,667**	**$26,503,394**	**$34,599,884**	**$35,070,886**	**$35,646,787**	**$37,186,577**	**$36,438,953**	**$37,081,188**	**$37,718,869**	**$38,318,677**	**$38,922,740**
CCA Total Bill	$0	$297,714,729	$389,196,008	$399,472,406	$409,344,443	$420,156,825	$431,255,172	$442,647,059	$454,340,264	$466,342,771	$478,662,778
SDG&E Total Bill	$0	$304,291,969	$397,802,511	$408,274,264	$419,021,676	$430,052,002	$441,372,691	$452,991,386	$464,915,931	$477,154,378	$489,714,990
Difference	$0	$6,577,240	$8,606,502	$8,801,858	$9,677,233	$9,895,177	$10,117,520	$10,344,328	$10,575,668	$10,811,607	$11,052,212
Total Bill Discount	0.0%	2.2%	2.2%	2.2%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
Effective Generation Rate Discount		4.8%	5.0%	5.0%	5.3%	5.3%	5.3%	5.3%	5.3%	5.2%	5.2%

TABLE 11-2. BASE CASE ANNUAL PROFORMA, ESCONDIDO ONLY, 100% RENEWABLE BY 2030

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Revenues from Operations ($)												
Electric Sales Revenues	$0	$40,924,260	$49,984,606	$51,119,786	$51,880,119	$53,053,753	$54,251,293	$55,473,115	$56,719,594	$57,991,106	$59,288,028	$60,610,734
Less Uncollected Accounts	$0	$81,849	$99,969	$102,240	$103,760	$106,108	$108,503	$110,946	$113,439	$115,982	$118,576	$121,221
Total Revenues	$0	$40,842,411	$49,884,636	$51,017,547	$51,776,359	$52,947,646	$54,142,791	$55,362,169	$56,606,155	$57,875,124	$59,169,452	$60,489,512
Cost of Operations ($)												
Cost of Energy	$0	$31,458,673	$40,882,201	$41,450,963	$41,915,160	$44,889,029	$45,690,052	$46,598,902	$47,503,941	$48,250,063	$49,014,318	$49,797,138
PCC1	$0	$550,849	$774,308	$832,781	$855,571	$3,475,508	$3,478,338	$3,603,361	$3,658,485	$3,754,791	$3,853,632	$3,955,075
PCC2	$0	$788,638	$1,124,579	$1,222,492	$1,272,049	$1,503,902	$1,589,936	$1,679,459	$1,772,592	$1,819,254	$1,867,144	$1,916,295
Resource Adequacy	$0	$7,646,613	$10,223,878	$10,499,689	$10,786,926	$11,068,680	$11,357,794	$11,654,460	$11,958,874	$12,271,240	$12,591,765	$12,920,662
CF Requirement	$0	$558,812	$778,641	$829,388	$844,001	$1,012,536	$1,073,449	$1,136,867	$1,202,880	$1,234,545	$1,267,043	$1,300,397
Miscellaneous CAISO	$0	$2,078,285	$2,815,411	$2,917,852	$3,024,021	$3,103,625	$3,185,325	$3,269,176	$3,355,234	$3,443,557	$3,534,205	$3,627,239
LT Renewable Contracts	$0	$9,585,214	$12,968,658	$13,411,537	$13,250,582	$9,864,532	$10,725,208	$11,316,781	$12,078,308	$12,153,193	$12,228,543	$12,304,360
Block Energy	$0	$10,250,261	$12,196,727	$11,737,223	$11,882,011	$14,860,246	$14,280,001	$13,938,798	$13,477,568	$13,573,483	$13,671,986	$13,773,110
Operating & Administrative												
Billing & Data Management	$0	$507,779	$693,658	$711,918	$730,658	$749,892	$769,632	$789,892	$810,685	$832,026	$853,928	$876,407
SDG&E Fees	$0	$173,662	$190,416	$195,428	$200,573	$205,853	$211,272	$216,833	$222,541	$228,399	$234,413	$240,584
Consulting Services	$278,333	$957,300	$1,122,714	$985,987	$1,005,707	$1,025,821	$1,046,337	$1,067,264	$1,088,609	$1,110,382	$1,132,589	$1,155,241
Staffing	$0	$696,165	$1,096,525	$1,278,369	$1,303,936	$1,330,015	$1,356,615	$1,383,747	$1,411,422	$1,439,651	$1,468,444	$1,497,813
General & Administrative expenses	$0	$158,763	$181,238	$163,638	$166,911	$190,649	$184,058	$177,127	$180,670	$204,683	$198,373	$191,728
Debt Service	$0	$1,449,311	$1,947,511	$1,947,511	$1,947,511	$1,947,511	$0	$0	$0	$0	$0	$0
Total O&A Costs	$278,333	$3,942,980	$5,232,061	$5,282,851	$5,355,296	$5,449,741	$3,567,915	$3,634,864	$3,713,928	$3,815,140	$3,887,746	$3,961,773
Total Cost	$278,333	$35,401,652	$46,114,262	$46,733,814	$47,270,456	$50,338,770	$49,257,966	$50,233,766	$51,217,869	$52,065,205	$52,902,067	$53,758,913
Net Income from Operations	($278,333)	$5,440,759	$3,770,374	$4,283,733	$4,505,903	$2,608,875	$4,884,824	$5,128,403	$5,388,286	$5,809,919	$6,267,385	$6,730,599
Cash from Operations and Financing												
Net Income	($278,333)	$5,440,759	$3,770,374	$4,283,733	$4,505,903	$2,608,875	$4,884,824	$5,128,403	$5,388,286	$5,809,919	$6,267,385	$6,730,599
Cash from Financing	$600,000	$8,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cash Available	$321,667	$13,440,759	$3,770,374	$4,283,733	$4,505,903	$2,608,875	$4,884,824	$5,128,403	$5,388,286	$5,809,919	$6,267,385	$6,730,599
Available For Reserves	$921,667	$14,362,425	$18,132,799	$22,416,532	$26,922,435	$29,531,310	$34,416,135	$39,544,538	$44,932,824	$50,742,743	$57,010,128	$63,740,727
Reserve Targets	$91,507	$11,638,899	$15,160,853	$15,364,542	$15,540,972	$16,549,733	$16,194,400	$16,515,211	$16,838,752	$17,117,328	$17,392,460	$17,674,163
Reserve Outlays												
CPUC Bond	$297,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$2,426,526	$248,420	$4,080,045	$4,329,472	$1,600,114	$5,240,157	$4,807,592	$5,064,745	$5,531,343	$5,992,252	$6,448,896
Total Reserve Outlays	$297,000	$2,426,526	$248,420	$4,080,045	$4,329,472	$1,600,114	$5,240,157	$4,807,592	$5,064,745	$5,531,343	$5,992,252	$6,448,896
Rate Stabilization Reserve Balance	**$624,667**	**$11,638,899**	**$15,160,853**	**$15,364,542**	**$15,540,972**	**$16,549,733**	**$16,194,400**	**$16,515,211**	**$16,838,752**	**$17,117,328**	**$17,392,460**	**$17,674,163**
CCA Total Bill	$0	$126,457,045	$164,870,088	$169,223,306	$173,293,439	$177,871,308	$182,570,271	$187,393,536	$192,344,397	$197,426,237	$202,642,526	$207,996,830
SDG&E Total Bill	$0	$129,255,285	$168,517,033	$172,953,075	$177,505,892	$182,178,557	$186,974,226	$191,896,135	$196,947,609	$202,132,058	$207,452,982	$212,913,974
Difference	$0	$2,798,240	$3,646,945	$3,729,770	$4,212,453	$4,307,249	$4,403,955	$4,502,600	$4,603,212	$4,705,821	$4,810,456	$4,917,145
Total Bill Discount	0.0%	2.2%	2.2%	2.2%	2.4%	2.4%	2.4%	2.3%	2.3%	2.3%	2.3%	2.3%
Effective Generation Rate Discount		4.8%	5.0%	5.0%	5.5%	5.5%	5.4%	5.4%	5.4%	5.4%	5.4%	5.3%

TABLE 11-3. BASE CASE ANNUAL PROFORMA, SAN MARCOS ONLY, 95% RENEWABLE BY 2030

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Revenues from Operations ($)											
Electric Sales Revenues	$0	$25,947,262	$32,010,382	$32,736,350	$33,310,794	$34,063,153	$34,830,787	$35,613,933	$36,412,827	$37,227,709	$38,058,815
Less Uncollected Accounts	$0	$51,895	$64,021	$65,473	$66,622	$68,126	$69,662	$71,228	$72,826	$74,455	$76,118
Total Revenues	$0	$25,895,367	$31,946,361	$32,670,877	$33,244,173	$33,995,027	$34,761,126	$35,542,705	$36,340,002	$37,153,254	$37,982,697
Cost of Operations ($)											
Cost of Energy	$0	$20,089,980	$26,362,951	$26,732,046	$27,182,238	$28,421,422	$28,863,277	$29,369,946	$29,869,036	$30,330,172	$30,802,347
PCC1	$0	$352,861	$500,231	$538,006	$578,211	$1,839,315	$1,782,372	$1,801,559	$1,772,668	$1,819,331	$1,867,223
PCC2	$0	$505,202	$726,532	$789,788	$855,786	$899,197	$944,300	$991,156	$1,039,823	$1,067,195	$1,095,288
Resource Adequacy	$0	$4,901,510	$6,609,336	$6,789,589	$6,954,102	$7,135,744	$7,322,129	$7,513,383	$7,709,633	$7,911,008	$8,117,644
CF Requirement	$0	$357,976	$503,039	$535,825	$570,330	$600,747	$632,370	$665,242	$699,406	$717,818	$736,713
Miscellaneous CAISO	$0	$1,331,351	$1,818,890	$1,885,072	$1,953,663	$2,005,091	$2,057,873	$2,112,044	$2,167,642	$2,224,703	$2,283,266
LT Renewable Contracts	$0	$6,140,332	$8,378,400	$8,664,522	$8,953,870	$6,372,961	$6,928,999	$7,311,183	$7,803,166	$7,851,546	$7,900,225
Block Energy	$0	$6,500,747	$7,826,524	$7,529,244	$7,316,276	$9,568,369	$9,195,234	$8,975,378	$8,676,698	$8,738,570	$8,801,987
Operating & Administrative											
Billing & Data Management	$0	$344,301	$470,543	$482,930	$495,643	$508,690	$522,081	$535,824	$549,929	$564,405	$579,263
SDG&E Fees	$0	$128,786	$129,169	$132,569	$136,059	$139,640	$143,316	$147,089	$150,961	$154,935	$159,014
Consulting Services	$278,333	$957,300	$1,122,714	$985,987	$1,005,707	$1,025,821	$1,046,337	$1,067,264	$1,088,609	$1,110,382	$1,132,589
Staffing	$0	$696,165	$1,096,525	$1,278,369	$1,303,936	$1,330,015	$1,356,615	$1,383,747	$1,411,422	$1,439,651	$1,468,444
General & Administrative expenses	$0	$158,763	$181,238	$163,638	$166,911	$190,649	$184,058	$177,127	$180,670	$204,683	$198,373
Debt Service	$0	$1,449,311	$1,947,511	$1,947,511	$1,947,511	$1,947,511	$0	$0	$0	$0	$0
Total O&A Costs	$278,333	$3,734,625	$4,947,700	$4,991,004	$5,055,767	$5,142,327	$3,252,408	$3,311,052	$3,381,592	$3,474,056	$3,537,683
Total Cost	$278,333	$23,824,606	$31,310,651	$31,723,051	$32,238,005	$33,563,749	$32,115,685	$32,680,998	$33,250,628	$33,804,228	$34,340,032
Net Income from Operations	($278,333)	$2,070,762	$635,710	$947,826	$1,006,168	$431,278	$2,645,440	$2,861,707	$3,089,374	$3,349,025	$3,642,665
Cash from Operations and Financing											
Net Income	($278,333)	$2,070,762	$635,710	$947,826	$1,006,168	$431,278	$2,645,440	$2,861,707	$3,089,374	$3,349,025	$3,642,665
Cash from Financing	$600,000	$8,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cash Available	$321,667	$10,070,762	$635,710	$947,826	$1,006,168	$431,278	$2,645,440	$2,861,707	$3,089,374	$3,349,025	$3,642,665
Available For Reserves	$921,667	$10,992,428	$11,628,138	$12,575,964	$13,582,132	$14,013,410	$16,658,850	$19,520,558	$22,609,932	$25,958,957	$29,601,621
Reserve Targets	$91,507	$7,832,747	$10,293,913	$10,429,496	$10,598,796	$11,034,657	$10,558,581	$10,744,438	$10,931,713	$11,113,719	$11,289,874
Reserve Outlays											
CPUC Bond	$297,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$2,862,681	$0	$0	$0	$0	$2,940,588	$2,675,851	$2,902,098	$3,167,019	$3,466,510
Total Reserve Outlays	$297,000	$2,862,681	$0	$0	$0	$0	$2,940,588	$2,675,851	$2,902,098	$3,167,019	$3,466,510
Rate Stabilization Reserve Balance	**$624,667**	**$7,832,747**	**$8,468,457**	**$9,416,283**	**$10,422,451**	**$10,853,729**	**$10,558,581**	**$10,744,438**	**$10,931,713**	**$11,113,719**	**$11,289,874**
CCA Total Bill	$0	$80,712,008	$106,090,012	$108,891,238	$111,600,125	$114,547,834	$117,573,500	$120,679,189	$123,867,022	$127,139,173	$130,497,878
SDG&E Total Bill	$0	$82,486,179	$108,425,533	$111,279,727	$114,209,055	$117,215,494	$120,301,075	$123,467,880	$126,718,049	$130,053,774	$133,477,310
Difference	$0	$1,774,172	$2,335,521	$2,388,489	$2,608,930	$2,667,660	$2,727,574	$2,788,691	$2,851,027	$2,914,601	$2,979,432
Total Bill Discount	0.0%	2.2%	2.2%	2.1%	2.3%	2.3%	2.3%	2.3%	2.2%	2.2%	2.2%
Effective Generation Rate Discount		4.8%	5.0%	5.0%	5.3%	5.3%	5.3%	5.2%	5.2%	5.2%	5.2%

TABLE 11-4. BASE CASE ANNUAL PROFORMA, VISTA ONLY, 90% RENEWABLE BY 2030

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Revenues from Operations ($)											
Electric Sales Revenues	$0	$25,947,262	$32,010,382	$32,736,350	$33,310,794	$34,063,153	$34,830,787	$35,613,933	$36,412,827	$37,227,709	$38,058,815
Less Uncollected Accounts	$0	$51,895	$64,021	$65,473	$66,622	$68,126	$69,662	$71,228	$72,826	$74,455	$76,118
Total Revenues	$0	$25,895,367	$31,946,361	$32,670,877	$33,244,173	$33,995,027	$34,761,126	$35,542,705	$36,340,002	$37,153,254	$37,982,697
Cost of Operations ($)											
Cost of Energy	$0	$20,089,980	$26,362,951	$26,732,046	$27,182,238	$28,421,422	$28,863,277	$29,369,946	$29,869,036	$30,330,172	$30,802,347
PCC1	$0	$352,861	$500,231	$538,006	$578,211	$1,839,315	$1,782,372	$1,801,559	$1,772,668	$1,819,331	$1,867,223
PCC2	$0	$505,202	$726,532	$789,788	$855,786	$899,197	$944,300	$991,156	$1,039,823	$1,067,195	$1,095,288
Resource Adequacy	$0	$4,901,510	$6,609,336	$6,789,589	$6,954,102	$7,135,744	$7,322,129	$7,513,383	$7,709,633	$7,911,008	$8,117,644
CF Requirement	$0	$357,976	$503,039	$535,825	$570,330	$600,747	$632,370	$665,242	$699,406	$717,818	$736,713
Miscellaneous CAISO	$0	$1,331,351	$1,818,890	$1,885,072	$1,953,663	$2,005,091	$2,057,873	$2,112,044	$2,167,642	$2,224,703	$2,283,266
LT Renewable Contracts	$0	$6,140,332	$8,378,400	$8,664,522	$8,953,870	$6,372,961	$6,928,999	$7,311,183	$7,803,166	$7,851,546	$7,900,225
Block Energy	$0	$6,500,747	$7,826,524	$7,529,244	$7,316,276	$9,568,369	$9,195,234	$8,975,378	$8,676,698	$8,738,570	$8,801,987
Operating & Administrative											
Billing & Data Management	$0	$344,301	$470,543	$482,930	$495,643	$508,690	$522,081	$535,824	$549,929	$564,405	$579,263
SDG&E Fees	$0	$128,786	$129,169	$132,569	$136,059	$139,640	$143,316	$147,089	$150,961	$154,935	$159,014
Consulting Services	$278,333	$957,300	$1,122,714	$985,987	$1,005,707	$1,025,821	$1,046,337	$1,067,264	$1,088,609	$1,110,382	$1,132,589
Staffing	$0	$696,165	$1,096,525	$1,278,369	$1,303,936	$1,330,015	$1,356,615	$1,383,747	$1,411,422	$1,439,651	$1,468,444
General & Administrative expenses	$0	$158,763	$181,238	$163,638	$166,911	$190,649	$184,058	$177,127	$180,670	$204,683	$198,373
Debt Service	$0	$1,449,311	$1,947,511	$1,947,511	$1,947,511	$1,947,511	$0	$0	$0	$0	$0
Total O&A Costs	$278,333	$3,734,625	$4,947,700	$4,991,004	$5,055,767	$5,142,327	$3,252,408	$3,311,052	$3,381,592	$3,474,056	$3,537,683
Total Cost	$278,333	$23,824,606	$31,310,651	$31,723,051	$32,238,005	$33,563,749	$32,115,685	$32,680,998	$33,250,628	$33,804,228	$34,340,032
Net Income from Operations	($278,333)	$2,070,762	$635,710	$947,826	$1,006,168	$431,278	$2,645,440	$2,861,707	$3,089,374	$3,349,025	$3,642,665
Cash from Operations and Financing											
Net Income	($278,333)	$2,070,762	$635,710	$947,826	$1,006,168	$431,278	$2,645,440	$2,861,707	$3,089,374	$3,349,025	$3,642,665
Cash from Financing	$600,000	$8,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cash Available	$321,667	$10,070,762	$635,710	$947,826	$1,006,168	$431,278	$2,645,440	$2,861,707	$3,089,374	$3,349,025	$3,642,665
Available For Reserves	$921,667	$10,992,428	$11,628,138	$12,575,964	$13,582,132	$14,013,410	$16,658,850	$19,520,558	$22,609,932	$25,958,957	$29,601,621
Reserve Targets	$91,507	$7,832,747	$10,293,913	$10,429,496	$10,598,796	$11,034,657	$10,558,581	$10,744,438	$10,931,713	$11,113,719	$11,289,874
Reserve Outlays											
CPUC Bond	$297,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Programs	$0	$2,862,681	$0	$0	$0	$0	$2,940,588	$2,675,851	$2,902,098	$3,167,019	$3,466,510
Total Reserve Outlays	$297,000	$2,862,681	$0	$0	$0	$0	$2,940,588	$2,675,851	$2,902,098	$3,167,019	$3,466,510
Rate Stabilization Reserve Balance	**$624,667**	**$7,832,747**	**$8,468,457**	**$9,416,283**	**$10,422,451**	**$10,853,729**	**$10,558,581**	**$10,744,438**	**$10,931,713**	**$11,113,719**	**$11,289,874**
CCA Total Bill	$0	$80,712,008	$106,090,012	$108,891,238	$111,600,125	$114,547,834	$117,573,500	$120,679,189	$123,867,022	$127,139,173	$130,497,878
SDG&E Total Bill	$0	$82,486,179	$108,425,533	$111,279,727	$114,209,055	$117,215,494	$120,301,075	$123,467,880	$126,718,049	$130,053,774	$133,477,310
Difference	$0	$1,774,172	$2,335,521	$2,388,489	$2,608,930	$2,667,660	$2,727,574	$2,788,691	$2,851,027	$2,914,601	$2,979,432
Total Bill Discount	0.0%	2.2%	2.2%	2.1%	2.3%	2.3%	2.3%	2.3%	2.2%	2.2%	2.2%
Effective Generation Rate Discount		4.8%	5.0%	5.0%	5.3%	5.3%	5.3%	5.2%	5.2%	5.2%	5.2%

12 Appendix B – Glossary

AB: Assembly Bill

Ancillary Services: Those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.

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)

Base Case: The base case is defined as the expected case involving expected power prices and electric loads.

Baseload Resources: Base load power generation resources are resources such as coal, nuclear, hydropower, and geothermal heat that are cheapest to operate when they generate approximately the same output every hour.

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).

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

Bundled and Unbundled Renewable RECs: Unbundled Renewable Energy Credits (RECs) are those that have been disassociated from the electricity production originally represented and are sold separately from energy. Bundled RECs are delivered with the associated energy.

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 Balancing Authority: A balancing authority is responsible for operating a transmission control area. It matches generation with load and maintains consistent electric frequency of the grid, even during extreme weather conditions or natural disasters. California has 8 balancing authorities. SDG&E is in CAISO.

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.

CARE: California Alternative Rates for Energy, a low-income program for affordable electric rates available to all IOU and CCA customers.

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 residents and become their electric generation provider.

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

Congestion Charges: When there is transmission congestion, i.e. more users of the transmission path than capacity, the CAISO charges all users of the congested transmission path a "Usage Charge".

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.

Cost Allocation Mechanism (CAM): is a regulatory process developed by the CPUC for allocating capacity costs of utility procurement equitably across all benefitting customers.

CO_2e: Carbon dioxide equivalent.

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.

Departing Load: Electric customer loads that were previously served by an investor-owned utility but are now served through direct access, municipalization, or CCA.

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 establishes a CCA by themselves as an enterprise within the local government entity.

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.

Firming: Firm capacity is the amount of energy available for production or transmission that can be (and in many cases must be) guaranteed to be available at a given time. Firm energy refers to the actual energy guaranteed to be available. Firming refers to the financial instrument to change non-firm power to firm power.

Flexible Resource Adequacy: Flexible capacity need is defined as the quantity of economically dispatched resources needed by the California ISO to manage grid reliability during the greatest three-hour continuous ramp in each month.

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 SP15, which corresponds closely to the price location that the County will pay to supply its load.

FTE: Full Time Equivalent.

Greenhouse Gas (GHG): Refers mainly to carbon dioxide.

GWh: Gigawatt Hour, 1,000 MWh.

IMPLAN: IMPLAN Group LLC's Input-Output Model.

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.

kW: Kilowatt, equal to 1,000 watts, is measure of electric demand.

kWh: Kilowatt Hour.

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

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.

Local Resource Adequacy: Local requirements are determined based on an annual CAISO study using a 1-10 weather year and an N-1-1 contingency.

Load Serving Entity (LSE): Includes IOUs, POUs, and Electric Service Providers, and CCAs.

Marginal Unit: An additional unit of power generation to what is currently being produced. At an 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.

Metric Tons (MT): 2,000 lbs.

MW: Megawatt equal to 1,000 kW.

MWh: Megawatt Hours equal to 1,000 kWh.

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), and 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 a source that does not come with a Renewable Energy Credit (REC).

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.

Opt-Up: The portion of CCA customers selecting 100% renewable portfolio content energy.

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

Photovoltaic (PV): Solar PV.

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.

Portfolio Content Category: California's RPS program defines all renewable procurement acquired from contracts executed after June 1, 2010 into three portfolio content categories.

Pricing Nodes: The ISO wholesale power market prices electricity based on the cost of generating and delivering it from particular grid locations called nodes.

Renewable Energy Credits (RECs): The renewable attributes from RPS-qualified resources that 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% 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. A scheduling coordinator provides day-ahead and real-time power and transmission scheduling services.

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

Shaping: Function that facilitate and supports the delivery of energy generation to periods when it is needed most.

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.

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.

SP15: Refers to a wholesale electricity-pricing hub - South of Path 15 - which roughly corresponds to SCE and SDG&E's service territory. Forward and Day-Ahead power contracts for Northern California typically provide for delivery at SP15. It is not a single location, but an aggregate based on the locations of all the generators in the region.

Spark Spread: The theoretical growth 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.

System Resource Adequacy: System requirements are determined based on each LSE's CEC adjusted forecast plus a 15% planning reserve margin.

Time-of-Use (TOU): Electric rate design where prices vary by time of electricity usage where on-peak periods are priced higher than off-peak periods.

Vintage: The vintage of CRS applicable to a CCA customer is determined based on when the CCA commits to begin providing generation services to the customer. CCAs may formally commit to become the generation service provider for a group of customers

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.

13 Appendix C – Implementation Schedule

	Q4 2021			Q1 2022			Q2 2022			Q3 2022			Q4 2022			Q1 2023			Q2 2023		
IMPLEMENTATION TIMELINE	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
First JPA Board Meeting (meets monthly)		X	ONGOING																		
Register JPA with Sec of State		X																			
Determine City staff support /roles; prepare cooperative services agreement		X	X																		
Continue weekly or bi-weekly planning team calls; include program vendors as needed		X	ONGOING																		
Prepare reports, provide updates for Member Agency City Council(s)		X	ONGOING																		
Obtain General and Regulatory Counsel		X	X	X																	
Set up Website				X																	
Obtain Technical Consultant			X	X																	
Obtain Financial Consultant and issue Banking Services RFP				X	X	X															
Multiple Services RFP and Contracting: Power Mgmt, Scheduling, Cust Service Call Center & Data Mgmt				X	X	X	X	X													
Prepare and adopt implementation budget; update and track						X	X	ONGOING													
Determine scope/selection of Board Committees and Advisory Committees										X	X	X									
Prepare Utility Service Agreement, Deposit and Bond Posting					X	X															
Select banking partner								X	X	X											
Determine Agency financial and accounting policies						X	X														
Review 2021 customer load data; verify load projections and proforma estimates					X	X	X														
Prepare resource adequacy procurement plan and RA compliance filings						X	X														
RPS Procurement Plans (2019 and 2020)						X			X												
Issue RFP for Marketing/Outreach								X													
Draft and Adopt Agency policies							X	X	X												
Secure necessary credit guarantees and establish access to credit line							X	X													
Secure marketing firm; develop public outreach and marketing plan								X	X	X	X										
Year Ahead RA							X														
Submit Registration Packet CPUC						X															
CEO Recruitment/Hire								X	X	X											
Develop and adopt FY 2020/2021 Budget								X	X												
Determine power supply mix for 2-3 product options								X	X												
IRP										X											
Approve staffing plan/initial staff hires and employment policies									X	X	ONGOING										
Determine plan for annual audits/begin monthly financials										X	ONGOING										
RPS Compliance Report										X											
Coordinate with SDG&E and data mgmt vendor to test for deposits& controls												X	X	X							
EDI certification (utility and bank)												X	X	X							
Develop and issue power supply RFP(s)													X	X	X						
Prepare/design customer enrollment notices													X	X	X						
Regulatory registrations for program compliance (CPUC, CAISO, WREGIS)														X	X	X					
Develop website 2.0 with translation and opt-out features														X	X	X					
Negotiate and finalize terms of initial power contracts										X	X	X	X	X	X	X					
Rate design & rate setting (incl PCIA, NEM and utility cost comparisons)														X	X	X					
Call center training/go live															X	X	X				
1st opt-out period (60 days out)																X					
2nd opt-out period (30 days out)																	X				
Utility account set up (dead period)																	X				
Account Switches/Customer enrollments																		X			
3rd opt-out period																			X		
4th opt-out period																				X	